BAYTEX ENERGY CORP.

BAYTEX DELIVERS RECORD PRODUCTION AND STRONG RESERVE GROWTH IN 2012

CALGARY, ALBERTA (March 7, 2013) - Baytex Energy Corp. (“Baytex”) (TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2012 (all amounts are in Canadian dollars unless otherwise noted).

Commenting on the results, James Bowzer, President and Chief Executive Officer of Baytex, said, "2012 was another very successful year for Baytex. In an environment which was especially challenging for heavy oil producers, Baytex was able to grow production by 8%, grow its reserve base by 16%, return over $215 million to its shareholders as dividends and reduce its total debt by over $50 million."

"This year also saw the successful execution of several strategic objectives, including the acquisition of 46 sections of undeveloped oil sands leases and an approved SAGD project at Cold Lake, the expansion of the land base at Peace River and the disposition of non-operated assets in North Dakota at attractive metrics."

James Bowzer said, "We continue to believe that transportation solutions to allow Canadian crude oil to access additional markets will proceed and that over time price discounts for Canadian production will narrow. Baytex is well positioned to benefit from an improving market, with quality assets and experienced staff."

Summary

- Produced record quarterly production of 55,046 boe/d (87% oil and natural gas liquids ("NGL")) in Q4/2012, an increase of 4% over Q4/2011 and 1% over Q3/2012, and record annual production of 53,986 boe/d (87% oil and NGL), an increase of 8% over 2011;

- Generated funds from operations (“FFO”) of $127.3 million ($1.05 per basic share) in Q4/2012, a decrease of 22% from Q4/2011 and 8% from Q3/2012, and $532.7 million ($4.44 per basic share) in full-year 2012, a decrease of 4% from 2011;

- Generated net income of $31.6 million ($0.26 per basic share) in Q4/2012, and $258.6 million ($2.16 per basic share) in full-year 2012, the highest level of annual net income in the company's history;

- Increased total proved plus probable reserves by 16% to 292 million boe, replacing 300% of 2012 production and extending our proved plus probable reserve life index to 14 years;

- Increased economic best estimate contingent resource by 2% to 795 million barrels of oil equivalent and bitumen, including a 4% increase at Peace River to 551 million barrels of bitumen;

- Recorded finding, development, and acquisitions (“FD&A”) costs in 2012 of $11.61/boe for proved plus probable reserves including changes in future development costs (“FDC”). Three-year average (2010 - 2012) FD&A costs are $14.06/boe for proved plus probable reserves including changes in FDC;

- Realized a recycle ratio (operating netback divided by FD&A costs) based on proved plus probable reserves (including changes in FDC) of 2.7x for 2012, and 2.3x for the three-year average;

- Maintained a conservative payout ratio, net of dividend reinvestment plan (“DRIP”) participation, of 43% (63% before DRIP) in Q4/2012 and 40% (60% before DRIP) in full-year 2012;

- Reduced total debt to $600 million at year-end 2012, 8% below that of one year ago; and

- Subsequent to year end, completed the sale of non-core Viking rights in the Kerrobert area, which included production of approximately 100 bbl/d, for total proceeds of $43 million.

	Three Months Ended			Years Ended	
	December 31, 2012	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**292,095**	299,786	367,813	**1,219,484**	1,308,814
Funds from operations (1)	**127,253**	139,044	162,973	**532,725**	555,483
Per share - basic	**1.05**	1.15	1.39	**4.44**	4.79
Per share - diluted	**1.04**	1.14	1.36	**4.37**	4.67
Cash dividends declared (2)	**55,043**	52,640	50,925	**215,184**	205,960
Cash dividends declared per share	**0.66**	0.66	0.62	**2.64**	2.42
Net income	**31,620**	26,773	57,780	**258,631**	217,432
Per share - basic	**0.26**	0.22	0.49	**2.16**	1.88
Per share - diluted	**0.26**	0.22	0.48	**2.12**	1.83
Exploration and development	**66,686**	113,126	72,013	**418,625**	367,848
Property acquisitions	**130,575**	958	10,329	**144,042**	76,164
Corporate acquisition	**—**	—	1,313	**—**	120,006
Proceeds from divestitures	**1,222**	1,202	(47,396)	**(314,978)**	(47,396)
Total oil and natural gas capital expenditures	**198,483**	115,286	36,259	**247,689**	516,622
Bank loan	**116,394**	181,785	311,960	**116,394**	311,960
Long-term debt	**449,235**	447,555	302,550	**449,235**	302,550
Working capital (surplus) deficiency	**34,197**	(149,329)	36,071	**34,197**	36,071
Total monetary debt (3)	**599,826**	480,011	650,581	**599,826**	650,581
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**7,739**	7,047	7,232	**7,360**	6,769
Heavy oil (bbl/d)	**40,257**	40,580	38,006	**39,447**	35,252
Total oil and NGL (bbl/d)	**47,996**	47,627	45,238	**46,807**	42,021
Natural gas (mmcf/d)	**42.3**	40.5	46.9	**43.1**	48.7
Oil equivalent (boe/d @ 6:1) (4)	**55,046**	54,381	53,054	**53,986**	50,132
Average prices (before hedging)					
WTI oil (US$/bbl)	**88.18**	92.22	94.06	**94.19**	95.12
Edmonton par oil ($/bbl)	**84.28**	84.79	97.87	**86.53**	95.56
BTE light oil and NGL ($/bbl)	**72.02**	70.34	85.09	**74.07**	82.49
BTE heavy oil ($/bbl) (5)	**54.58**	60.11	70.85	**59.44**	65.53
BTE total oil and NGL ($/bbl)	**57.39**	61.63	73.13	**61.74**	68.26
BTE natural gas ($/mcf)	**3.03**	2.34	3.91	**2.45**	4.17
BTE oil equivalent ($/boe)	**52.37**	55.70	65.81	**55.48**	61.26
CAD/USD noon rate at period end	**0.9949**	0.9837	1.0170	**0.9949**	1.0170
CAD/USD average rate for period	**0.9913**	0.9953	1.0231	**0.9991**	0.9887

	Three Months Ended			Years Ended	
	December 31, 2012	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**48.35**	50.37	57.26	**59.40**	58.76
Low	**41.91**	39.91	39.18	**38.54**	39.18
Close	**42.87**	46.72	56.97	**42.87**	56.97
Volume traded (thousands)	**25,108**	25,679	26,471	**108,327**	111,236
NYSE					
Share price (US$)					
High	**49.25**	51.73	56.33	**59.50**	61.95
Low	**42.20**	39.50	36.39	**37.40**	36.89
Close	**43.24**	47.44	55.89	**43.24**	55.89
Volume traded (thousands)	**3,567**	5,823	7,579	**22,135**	37,384
Common shares outstanding (thousands)	**121,868**	120,962	117,893	**121,868**	117,893

Notes:

(1) Funds from operations is a non-GAAP measure that represents cash generated from operating activities adjusted for finance costs, changes in non-cash operating working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends and capital investments. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three months and year ended December 31, 2012.

(2) Cash dividends declared are net of DRIP participation.

(3) Total monetary debt is a non-GAAP measure which we define to be the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as deferred income tax assets or liabilities and unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loans.

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

(5) Heavy oil prices are net of blending costs.

Operations Review

Production averaged 55,046 boe/d (87% oil and NGL) during Q4/2012, as compared to 53,054 boe/d (86% oil and NGL) in Q4/2011 and 54,381 boe/d (88% oil and NGL) in Q3/2012. Compared to Q4/2011, oil and NGL production increased 6%, while natural gas production decreased 10%. Compared to Q3/2012, oil and NGL production increased 1%, while natural gas production increased 4%. During 2012, we focused our capital investment on more profitable crude oil investment opportunities resulting in minimal drilling activity for natural gas.

Capital expenditures for exploration and development activities totaled $66.7 million for Q4/2012 and $418.6 million for full-year 2012. During Q4/2012, Baytex participated in the drilling of 28 (20.4 net) wells with a 100% success rate. For full-year 2012, Baytex participated in the drilling of 209 (162.6 net) wells with a 98% success rate.

Our 2013 production guidance remains at 56,000 to 58,000 boe/d with 2013 exploration and development capital expenditures forecast to be approximately $520 million (which includes $90 million for long term thermal projects which will not contribute to current year production). Consistent with our budget expectations for the full-year and the timing of our development program, we expect production during Q1/2013 to average approximately 52,000 boe/d. Our production mix for 2013 is forecast to be 75% heavy oil, 14% light oil and NGL and 11% natural gas.

Wells Drilled - Three months ended December 31, 2012

	Crude Oil											
	Primary		Thermal		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster area	10	7.7	—	—	—	—	—	—	—	—	10	7.7
Peace River area	6	6.0	—	—	—	—	4	4.0	—	—	10	10.0
	16	**13.7**	**—**	**—**	**—**	**—**	**4**	**4.0**	**—**	**—**	**20**	**17.7**
Light oil, NGL and natural gas												
Western Canada	—	—	—	—	1	1.0	—	—	—	—	1	1.0
North Dakota	7	1.7	—	—	—	—	—	—	—	—	7	1.7
	7	**1.7**	**—**	**—**	**1**	**1.0**	**—**	**—**	**—**	**—**	**8**	**2.7**
Total	**23**	**15.4**	**—**	**—**	**1**	**1.0**	**4**	**4.0**	**—**	**—**	**28**	**20.4**

Wells Drilled - Year ended December 31, 2012

	Crude Oil											
	Primary		Thermal		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil												
Lloydminster area	87	74.8	—	—	—	—	1	1.0	2	2.0	90	77.8
Peace River area	33	33.0	5	5.0	—	—	17	17.0	—	—	55	55.0
	120	**107.8**	**5**	**5.0**	**—**	**—**	**18**	**18.0**	**2**	**2.0**	**145**	**132.8**
Light oil, NGL and natural gas												
Western Canada	18	14.3	—	—	4	4.0	—	—	1	1.0	23	19.3
North Dakota	41	10.5	—	—	—	—	—	—	—	—	41	10.5
	59	**24.8**	**—**	**—**	**4**	**4.0**	**—**	**—**	**1**	**1.0**	**64**	**29.8**
Total	**179**	**132.6**	**5**	**5.0**	**4**	**4.0**	**18**	**18.0**	**3**	**3.0**	**209**	**162.6**

Heavy Oil

In Q4/2012, heavy oil production averaged 40,257 bbl/d, an increase of 6% over Q4/2011 and a decrease of 1% compared to Q3/2012. During Q4/2012, we drilled 16 (13.7 net) oil wells on our heavy oil properties with a success rate of 100%.

Production from our Peace River area properties averaged approximately 21,000 bbl/d in Q4/2012, an increase of 20% over Q4/2011 and a decrease of 2% from Q3/2012. In Q4/2012, we drilled four (4.0 net) stratigraphic test wells and six (6.0 net) horizontal oil wells in the Peace River area (encompassing a total of 83 laterals). The six horizontal oil wells established average 30-day peak production rates of approximately 400 bbl/d. We plan to drill approximately 37 multi-lateral horizontal wells and approximately 26 stratigraphic test wells in the Peace River area in 2013.

In the Cliffdale area, successful operations continued at our 10-well commercial cyclic steam stimulation ("CSS") module, with production during Q4/2012 averaging approximately 400 bbl/d. The cumulative steam-oil-ratio for the project is 2.4, consistent with project design parameters. During Q4/2012, seven wells received steam and six wells commenced post-steam flowback operations. We continue to plan for a new 15-well commercial CSS module at Cliffdale. Upon receipt of regulatory approvals, we will commence facility construction with drilling operations planned for Q3/2013.

In our Lloydminster heavy oil area, Q4/2012 drilling included seven (6.3 net) horizontal oil wells and three (1.4 net) vertical oil wells. We plan to drill 108 wells in the Lloydminster area in 2013, approximately evenly split between horizontal and vertical wells.

In Q4/2012, we completed the previously disclosed acquisition of a 100% working interest in 46 sections of undeveloped oil sands leases in the Angling Lake (Cold Lake) area of northern Alberta for total consideration of $120 million. The lands are proximal to our existing Cold Lake heavy oil assets and are prospective for both cold and thermal development. We expect to commence construction of the Gemini steam-assisted gravity drainage ("SAGD") pilot facilities in the second quarter of 2013.

Light Oil & Natural Gas

During Q4/2012, light oil, NGL and natural gas production averaged 14,789 boe/d, which was comprised of 7,739 bbl/d of light oil and NGL and 42.3 mmcf/d of natural gas. Compared to Q4/2011, light oil and NGL production increased 7% and natural gas production decreased 10%. Compared to Q3/2012, light oil and NGL production increased 10%, and natural gas production increased 4%.

In our Bakken/Three Forks play in North Dakota, we participated in the drilling of seven (1.7 net) horizontal oil wells, six of which were Baytex-operated, and the fracture-stimulation of six (1.8 net) wells in Q4/2012. During Q4/2012, eleven Baytex-operated wells on 1,280-acre spacing established average 30-day peak rates of approximately 475 boe/d. We plan to drill approximately 20 (9.0 net) wells on our Bakken/Three Forks play in North Dakota in 2013.

Subsequent to the end of Q4/2012, we closed the sale of approximately 22,000 net acres of non-core Viking rights in the Kerrobert area of southwest Saskatchewan for $43 million. Production associated with the disposition was approximately 100 bbl/d.

Financial Review

We generated FFO of $127.3 million ($1.05 per basic share) in Q4/2012, a decrease of 22% compared to Q4/2011, and a decrease of 8% compared to Q3/2012. The decrease relative to Q4/2011 and Q3/2012 was largely the result of lower realized oil prices. The Q4/2012 results are net of a non-recurring increase to royalty expense of $4.4 million. Full-year 2012 FFO was $532.7 million ($4.44 per basic share), a decrease of 4% compared to 2011. This decrease was largely due to lower realized oil prices, partially offset by increased sales volumes.

We generated net income of $31.6 million ($0.26 per basic share) in Q4/2012, an increase of 18% over Q3/2012, and a decrease of 45% from Q4/2011. On an annual basis we generated record net income of $258.6 million ($2.16 per basic share) in 2012, an increase of 19% over 2011. The 2012 net income includes the gain on disposition of our North Dakota assets of $172.5 million ($103.5 million after income tax expense).

The average WTI price for Q4/2012 was US$88.18/bbl, a 6% decrease from Q4/2011 and a 4% decrease from Q3/2012. We received an average oil and NGL price of $57.39/bbl in Q4/2012 (inclusive of our physical hedging gains), down 22% from $73.13/bbl for Q4/2011 and down 7% from $61.63/bbl for Q3/2012. For the full-year 2012, WTI price averaged US$94.19/bbl, a 1% decrease from 2011. We received an average oil and NGL price of $61.74/bbl in 2012 (inclusive of our physical hedging gains), down 10% from $68.26/bbl for 2011. Our realized oil prices include the impact of sales to new markets by rail, which averaged approximately 8,400 bbl/d of raw bitumen for Q4/2012, and was approximately 7,500 bbl/d for 2012.

The discount for Canadian heavy oil, as measured by the Western Canadian Select (“WCS”) price differential to WTI, averaged 21% in Q4/2012, as compared to 24% in Q3/2012. As Q4/2012 progressed, the monthly WCS differential widened due to higher U.S. refinery outages as well as apportionment of access to the main Canadian export pipeline systems. For the year ended December 31, 2012, the WCS price differential averaged 22%, as compared to 18% in 2011.

In this volatile differential environment, Baytex continues to actively hedge its exposure to commodity prices and foreign exchange rates. We have established forward contracts for Q1/2013 on approximately 47% of our WTI exposure at a fixed price of US$98.46/bbl, 43% of our exposure to WCS heavy oil differentials through a combination of long term physical supply contracts and rail delivery, 20% of our natural gas price exposure, and 33% of our exposure to currency movements between the U.S. and Canadian dollars. Details of our hedging contracts are contained in the notes to our financial statements.

We continue to monitor the markets for opportunities to add to our hedge positions. As part of our hedging program, we are focused on opportunities to further mitigate our exposure to WCS price differentials by transporting crude oil to higher value markets by railway. By the end of Q1/2013, we expect to be delivering approximately 40% of our heavy oil volumes by rail, and we continue to explore opportunities for additional rail deliveries.

We ended the year with total monetary debt of $600 million representing a debt-to-FFO ratio of 1.1 times, based on FFO over the trailing twelve-month period. Baytex further improved our already significant financial liquidity in 2012, having over $580 million of available undrawn credit facilities at year-end, and no long-term debt maturities until 2021. The acquisition of the Cold Lake lands in Q4/2012 were funded by a draw on our credit facilities, and the proceeds from the Q1/2013 sale of the Kerrobert Viking rights have been used to repay amounts outstanding on our credit facilities.

Year-End 2012 Reserves

Baytex's year-end 2012 reserves are evaluated by Sproule Associates Limited (“Sproule”), the independent reserves evaluator for all of Baytex's oil and gas properties, in accordance with National Instrument 51-101 “Standards of Disclosure for Oil and Gas Activities” (“NI 51-101”). In 2012, reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake), and Kerrobert have been classified as bitumen, in accordance with NI 51-101. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2012, which will be filed in late March 2013.

Highlights of the 2012 reserve report include:

- Total proved plus probable reserves increased 16% to 292 million boe and increased 12% on a per-share basis. Year-end 2012 proved plus probable reserves are comprised of 93% oil and NGL and 7% natural gas;

- Reserve life index on a proved plus probable basis is 14.0 years based on the mid-point of our 2013 production guidance of 57,000 boe/d;

- Year-end 2012 reserves reflect continued growth of our heavy oil and bitumen reserves to 223 million barrels of proved plus probable reserves, an increase of 25% over 2011;

- Exploration and development capital expenditures in 2012 totaled $419 million. Property acquisitions were $144 million and proceeds of disposition were $315 million, which resulted in a total net capital outlay in 2012 of $248 million. This level of net expenditures resulted in the net addition of 58.9 million boe on a proved plus probable basis;

- Inclusive of acquisitions and divestitures, replaced 300% of production, with FD&A costs of $11.61 per boe for proved plus probable reserves including changes in FDC. Three-year average (2010 - 2012) FD&A costs are $14.06 per boe for proved plus probable reserves including changes in FDC;

- Replaced 170% of production through exploration and development activities (excluding acquisitions and divestitures) with finding and development costs of $19.88/boe, including changes in FDC. Three-year average (2010-2012) finding and development costs are $16.61/boe, including changes in FDC;

- Generated a recycle ratio (operating netback divided by FD&A costs) based on proved plus probable reserves (including changes in FDC) of 2.7x in 2012 and 2.3x for the three-year average;

- At Peace River, proved plus probable reserves increased 8% to 110.0 million barrels, consisting of 63.6 million barrels of primary (cold) reserves and 46.4 million barrels of bitumen reserves associated with our Cliffdale thermal project;

- At our Gemini SAGD project in the Angling Lake (Cold Lake) region of northeast Alberta, proved plus probable bitumen reserves totaled 43.6 million barrels; and

- In our light oil resource play in North Dakota, proved plus probable reserves increased 5% to 34.4 million boe, inclusive of the 2012 divestiture of 18.1 million boe of proved plus probable reserves.

Petroleum and Natural Gas Reserves as at December 31, 2012

The following table sets forth our gross and net reserve volumes at December 31, 2012 by product type and reserve category using Sproule's forecast prices and costs. Please note that the data in the table may not add due to rounding.

	Forecast Prices and Costs					
	Heavy Oil		Bitumen		Light and Medium Crude Oil	
Reserve Category	Gross (1) (mbbl)	Net (2) (mbbl)	Gross (1) (mbbl)	Net (2) (mbbl)	Gross (1) (mbbl)	Net (2) (mbbl)
Proved						
Developed Producing	36,440	29,561	5,432	4,604	9,273	7,398
Developed Non-Producing	10,826	8,923	—	—	111	102
Undeveloped	32,577	27,164	14,044	12,261	15,735	13,096
Total Proved	79,843	65,648	19,476	16,865	25,119	20,596
Probable	42,021	34,242	82,085	64,805	14,079	11,303
Total Proved Plus Probable	121,864	99,890	101,561	81,670	39,198	31,899

	Forecast Prices and Costs					
	Natural Gas Liquids		Natural Gas		Oil Equivalent (3)	
Reserve Category	Gross (1) (mbbl)	Net (2) (mbbl)	Gross (1) (mmcf)	Net (2) (mmcf)	Gross (1) (mboe)	Net (2) (mboe)
Proved						
Developed Producing	2,356	1,749	50,414	44,108	61,903	50,663
Developed Non-Producing	116	79	3,256	2,733	11,595	9,560
Undeveloped	3,316	2,637	25,638	20,596	69,946	58,590
Total Proved	5,788	4,465	79,308	67,437	143,444	118,813
Probable	3,424	2,591	39,257	32,623	148,152	118,379
Total Proved Plus Probable	9,212	7,056	118,565	100,060	291,596	237,192

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) 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.

Reserve Reconciliation

The following table reconciles the year-over-year changes in our gross reserve volumes by product type and reserve category using Sproule's forecast prices and costs.

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

	Heavy Oil			Bitumen		
	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)
December 31, 2011	90,058	43,930	133,988	18,036	27,221	45,257
Extensions	5,267	4,837	10,104	1,166	10,021	11,187
Discoveries	—	—	—	—	—	—
Improved Recoveries	281	513	794	—	—	—
Technical Revisions	(1,531)	(7,217)	(8,748)	125	1,924	2,049
Acquisitions	49	8	57	731	42,898	43,629
Dispositions	(16)	(3)	(19)	—	—	—
Economic Factors	(388)	(47)	(435)	(22)	21	(1)
Production	(13,877)	—	(13,877)	(560)	—	(560)
December 31, 2012	79,843	42,021	121,864	19,476	82,085	101,561

	Light and Medium Crude Oil			Natural Gas Liquids		
	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)	Proved (mboe)	Probable (mboe)	Proved + Probable (mboe)
December 31, 2011	28,224	15,010	43,234	5,766	2,857	8,623
Extensions	8,955	6,953	15,908	1,874	1,390	3,264
Discoveries	31	9	40	2	—	2
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	(151)	(3,615)	(3,766)	399	26	425
Acquisitions	—	—	—	—	—	—
Dispositions	(9,844)	(4,308)	(14,152)	(1,611)	(782)	(2,393)
Economic Factors	(4)	30	26	(40)	(66)	(106)
Production	(2,092)	—	(2,092)	(602)	—	(602)
December 31, 2012	25,119	14,079	39,198	5,788	3,425	9,213

	Natural Gas			Oil Equivalent [3]		
	Proved (mmcf)	Probable (mmcf)	Proved + Probable (mmcf)	Proved (mboe)	Probable (mboe)	Proved + Probable (mboe)
December 31, 2011	86,870	39,572	126,442	156,562	95,613	252,175
Extensions	13,543	8,349	21,892	19,519	24,593	44,112
Discoveries	89	31	120	48	14	62
Improved Recoveries	—	—	—	281	513	794
Technical Revisions	3,225	(3,702)	(477)	(620)	(9,499)	(10,119)
Acquisitions	—	—	—	780	42,906	43,686
Dispositions	(6,476)	(3,124)	(9,600)	(12,550)	(5,614)	(18,164)
Economic Factors	(2,177)	(1,869)	(4,046)	(817)	(374)	(1,191)
Production	(15,766)	—	(15,766)	(19,759)	—	(19,759)
December 31, 2012	79,308	39,257	118,565	143,444	148,152	291,596

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) Reserve information as at December 31, 2012 and 2011 is prepared in accordance with NI 51-101.
(3) 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 6 mcf:1 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.

Reserve Life Index

The following table sets forth our reserve life index based on total proved and proved plus probable reserves and the mid-point of our 2013 production guidance of 57,000 boe/d.

	Mid-Point of 2013 Production Guidance	Reserve Life Index (years) Total Proved	Reserve Life Index (years) Proved Plus Probable
Oil and NGL (bbl/d)	50,700	7.0	14.7
Natural Gas (mmcf/d)	37.8	5.7	8.6
Oil Equivalent (boe/d)	57,000	6.9	14.0

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent reserve evaluator, Sproule, the efficiency of our capital programs is summarized in the following table:

	2012	2011	2010	Three-Year Average 2010 - 2012
Excluding Future Development Costs				
FD&A costs - Proved ($/boe)				
Exploration and development[1]	**$ 22.81**	$ 13.55	$ 9.54	**$ 14.55**
Acquisitions (net of dispositions)	**14.52**	19.79	21.84	**(11.58)**
Total	**$ 37.60**	$ 14.90	$ 10.52	**$ 15.36**
FD&A costs - Proved plus probable ($/boe)				
Exploration and development[1]	**$ 12.46**	$ 12.25	$ 5.41	**$ 9.52**
Acquisitions (net of dispositions)	**(6.70)**	13.03	10.96	**0.59**
Total	**$ 4.19**	$ 12.46	$ 5.90	**$ 7.05**
Operating netback per boe[2]	**$ 31.09**	$ 34.68	$ 32.27	**$ 32.83**
Recycle ratio based on operating netback[2]				
Proved plus probable	**7.4**	2.8	5.5	**4.7**
Including Future Development Costs				
FD&A costs - Proved ($/boe)				
Exploration and development[1]	**$ 29.22**	$ 23.66	$ 15.22	**$ 22.13**
Acquisitions (net of dispositions)	**28.79**	25.22	32.71	**37.51**
Total	**$ 30.00**	$ 24.00	$ 16.61	**$ 21.66**
FD&A costs - Proved plus probable ($/boe)				
Exploration and development[1]	**$ 19.88**	$ 19.02	$ 12.44	**$ 16.61**
Acquisitions (net of dispositions)	**0.72**	17.39	20.68	**7.40**
Total	**$ 11.61**	$ 18.57	$ 13.17	**$ 14.06**
Recycle ratio based on operating netback[2]				
Proved plus probable	**2.7**	1.9	2.5	**2.3**

Notes:
(1) 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 reserve additions for that year.
(2) Recycle ratio is calculated as operating netback divided by FD&A costs (proved plus probable including/excluding FDC). Operating netback is calculated as revenue (including realized hedging gains and losses) minus royalties, operating expenses and transportation expenses.

Net Present Value of Reserves (Forecast Prices and Costs)

The following table summarizes Sproule's estimate 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).

	Summary of Net Present Value of Future Net Revenue As at December 31, 2012 Before Income Taxes and Discounted at (%/year)				
Reserve Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed Producing	1,813,542	1,521,905	1,324,545	1,181,525	1,072,763
Developed Non-Producing	355,594	279,228	225,234	185,787	156,153
Undeveloped	1,671,627	1,130,375	787,895	563,180	409,028
Total Proved	3,840,763	2,931,508	2,337,674	1,930,492	1,637,944
Probable	4,332,253	2,345,156	1,423,080	932,807	645,254
Total Proved Plus Probable	8,173,016	5,276,664	3,760,754	2,863,299	2,283,198

The net present values noted in the table above do not include any value for future net revenue which may ultimately be generated from the contingent resources discussed later in this press release.

Sproule December 31, 2012 Forecast Prices

The following table summarizes the forecast prices used by Sproule in preparing the estimated reserve volumes and the net present values of future net revenues at December 31, 2012. Sproule's forecast price assumptions on crude oil and natural gas reflect a decrease from their price assumptions used at December 31, 2011.

Year	WTI Cushing US$/bbl	Edmonton Par Price C$/bbl	Western Canada Select C$/bbl	AECO C-Spot C$/ MMbtu	Inflation Rate %/Yr	Exchange Rate $Cdn/$US
2012 act.	94.19	86.53	73.04	2.43	1.3	0.999
2013	89.63	84.55	69.33	3.31	1.5	0.999
2014	89.93	89.84	74.57	3.72	1.5	0.999
2015	88.29	88.21	73.21	3.91	1.5	0.999
2016	95.52	95.43	80.17	4.70	1.5	0.999
2017	96.96	96.87	81.37	5.32	1.5	0.999
2018	98.41	98.32	82.59	5.40	1.5	0.999
2019	99.89	99.79	83.83	5.49	1.5	0.999
2020	101.38	101.29	85.08	5.58	1.5	0.999
2021	102.91	102.81	86.36	5.67	1.5	0.999
2022	104.45	104.35	87.66	5.76	1.5	0.999
2023	106.02	105.92	88.97	5.85	1.5	0.999

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below (using forecast prices and costs).

Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2013	321,550	425,342
2014	263,544	453,689
2015	185,867	342,760
2016	174,944	259,041
2017	32,393	148,670
Remaining	74,384	282,894
Total (Undiscounted)	1,052,682	1,912,396

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2012.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	674,657	546,988
British Columbia	54,263	29,284
Saskatchewan	204,910	179,691
Total Canada	933,830	755,963
Total United States	168,463	108,978
Grand Total	1,102,293	864,941

Contingent Resource Assessment

We commissioned Sproule to conduct an assessment of contingent resource effective December 31, 2012 on three of our oil resource plays: the Bluesky in the Peace River area of Alberta, the Lower Cretaceous Mannville Group in the Angling Lake (Cold Lake) area of Alberta and the Bakken/Three Forks in North Dakota. We also commissioned McDaniel & Associates Consultants Ltd. ("McDaniel") to conduct an assessment of contingent resource effective December 31, 2012 on Lower Cretaceous Mannville Group in northeast Alberta. As a result of dispositions of certain of our leases, we no longer present contingent resource estimates for our Viking land position.

Contingent resource represents the quantity of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs.

For the total of these four plays, Sproule and McDaniel's estimate of economic contingent resource ranges from 622 million barrels of oil equivalent and bitumen in the "low estimate" (C1) to 1,160 million barrels of oil equivalent and bitumen in the "high estimate" (C3), with a "best estimate" (C2) of 795 million barrels of oil equivalent and bitumen. Contingent resources are in addition to currently booked reserves.

The best estimate contingent resource of 795 million barrels of oil equivalent and bitumen represents a 2% increase over year-end 2011. The best estimate contingent resource for Peace River of 551 million barrels of bitumen represents a 4% increase over year-end 2011, and is largely attributable to new data being gathered from our stratigraphic test well program. For our Cold Lake oil sands leases acquired in 2012, the best estimate contingent resource is 87 million barrels of bitumen, which reflects the thermal potential on the acquired lands beyond the approved Gemini SAGD project. Notable changes to our Bakken/Three Forks contingent resource assessment include adjustments for the disposition of non-operated assets in North Dakota, land adjustments and the conversion of resources to reserves during the year.

The tables below summarize Sproule's estimate of gross reserves and Sproule and McDaniel's estimates of economic contingent resource for the four plays by geographic area.

	Forecast Prices and Costs(2)			
	Proved plus Probable Gross Reserves(4) As at Dec. 31, 2012	Contingent Resources (gross)(1)(5) As at Dec. 31, 2012		
(millions of barrels of oil equivalent and bitumen)(3)		**Low(6)**	**Best(7)**	**High(8)**
Peace River, Alberta	110.0	458	551	781
Northeast Alberta	4.0	70	130	202
Angling Lake (Cold Lake acquisition), Alberta	43.6	78	87	127
Bakken/Three Forks, North Dakota, USA	34.4	16	27	50
Total	192.0	622	795	1,160

Notes:

(1) The contingent resource assessments were prepared in accordance with the definitions, standards and procedures contained in the COGE Handbook and NI 51-101. Contingent resource is defined in the COGE Handbook as "those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets."

(2) Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs.

(3) Under NI 51-101, naturally occurring hydrocarbons with a viscosity greater than 10,000 centipoise are classed as bitumen. All of the contingent resource at Peace River and Angling Lake that will be recovered by thermal processes has a viscosity greater than this value; therefore, this component of the contingent resource is classified as bitumen under NI 51-101.

(4) Proved plus probable gross reserve volumes are based on the Sproule Report.

(5) Sproule and McDaniel prepared the estimates of contingent resource shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table. Gross means the company's working interest share in the contingent resource before deducting royalties.

(6) Low estimate (C1) is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources in the low estimate have the highest degree of certainty - a 90% confidence level - that the actual quantities recovered will equal or exceed the estimate.

(7) Best estimate (C2) is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources in the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate.

(8) High estimate (C3) is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will equal or exceed the high estimate. Those resources in the high estimate have a lower degree of certainty - a 10% confidence level - that the actual quantities recovered will equal or exceed the estimate.

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that we will produce any portion of the volumes currently classified as contingent resource. The recovery and resource estimates provided herein are estimates. Actual contingent resource (and any volumes that may be reclassified as reserves) and future production from such contingent resource may be greater than or less than the estimates provided herein.

Additional Information

Our unaudited interim condensed consolidated financial statements for the three months and years ended December 31, 2012 and 2011 and related Management's Discussion and Analysis of the operating and financial results can be accessed immediately on our website at www.baytex.ab.ca 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 7, 2013, starting at 9:00am MST (11:00am EST). To participate, please dial 416-340-2218 or toll free in North America 1-866-226-1793 and toll free international 800-9559-9853. Alternatively, to listen to the conference call online, please enter http://events.digitalmedia.telus.com/baytex/030713/index.php in your web browser.

An archived recording of the conference call will be available until March 14, 2013 by dialing toll free 1-800-408-3053 within North America (Toronto local dial 905-694-9451, International toll free 800-3366-3052) and entering reservation code 7190805. The conference call will also be archived on the Baytex website at www.baytex.ab.ca.

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: our average production rate for the first quarter of 2013 and for full-year 2013; our exploration and development capital expenditures for 2013; our production mix for 2013; development plans for our properties, including the number of wells to be drilled in the full-year 2013; initial production rates from wells drilled; our Cliffdale cyclic steam stimulation project, including our assessment of the steam and flowback operations, the cumulative steam-oil ratio for the project and our plan for a second commercial module of CSS; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate; the existence, operation and strategy of our risk management program for commodity prices, heavy oil differentials and interest and foreign exchange rates; our ability to mitigate our exposure to heavy oil price differentials by transporting our crude oil to market by railways; the volume of heavy oil to be transported to market on railways in the first quarter of 2013; the amount of our undrawn credit facilities at December 31, 2012; our debt-to-FFO ratio; our liquidity and financial capacity; the sufficiency of our financial resources to fund our operations; our reserve life index; forecast prices for oil and natural gas; forecast interest and exchange rates; and future development costs. 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 the reserves can be profitably produced in the future. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of FFO and capital expenditures and our prevailing financial circumstances at the time.

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; the receipt, in a timely manner, of regulatory and other required approvals; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period 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: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; failure to obtain the necessary regulatory and other approvals on the planned timelines; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2011, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast 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.

Non-GAAP Financial Measures

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

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

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, 2012, which will be filed later in March 2013. 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.*

- *This press release contains reserves estimates for our Peace River (Bluesky), Northeast Alberta (Mannville), Angling Lake/Cold Lake (Mannville) and North Dakota (Bakken/Three Forks) properties. Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation.*

- *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 reserve 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 estimates as of December 31, 2012 of the volumes of the "contingent resource" for four of our oil resource plays: the Bluesky in the Peace River area of Alberta; the Mannville group in northeast Alberta; the Mannville group in Angling Lake (Cold Lake) area of Alberta; and the Bakken/Three Forks in North Dakota. These estimates were prepared by independent qualified reserves evaluators.

"Contingent resource" is not, and should not be confused with, petroleum and natural gas reserves. "Contingent resource" is defined in the Canadian Oil and Gas Evaluation Handbook as: "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage." The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs.

The primary contingencies which currently prevent the classification of the contingent resource as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices; future drilling program and testing results; further reservoir delineation and studies; facility design work; limitations to development based on adverse topography or other surface restrictions; and the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that we will produce any portion of the volumes currently classified as contingent resource. The estimates of contingent resource involve implied assessment, based on certain estimates and assumptions, that the resource described exists in the quantities predicted or estimated and that the resource can be profitably produced in the future. The net present value of the future net revenue from the contingent resource does not necessarily represent the fair market value of the contingent resource.

The recovery and resource estimates provided herein are estimates only. Actual contingent resource (and any volumes that may be reclassified as reserves) and future production from such contingent resource may be greater than or less than the estimates provided herein.

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

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" (both as defined in SEC rules). Canadian securities laws require oil and gas issuers, in their filings with Canadian securities regulatory authorities, to disclose not only "proved reserves" but also "probable reserves" (both as defined in NI 51-101), both of which are defined differently from the SEC rules. Accordingly, proved, probable and proved plus 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.

We also included in this press release estimates of contingent resource. Contingent resource represents the quantity of petroleum and natural gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. The SEC does not permit the inclusion of estimates of resource in reports filed with it by United States companies.

Baytex Energy Corp.

Baytex Energy Corp. is a dividend-paying 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 Williston Basin in the United States. Approximately 87% of Baytex's production is weighted toward crude oil. Baytex pays a monthly dividend on its common shares which are traded 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.baytex.ab.ca or contact:

Brian Ector, Vice President, Investor Relations

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