BAYTEX REPORTS RECORD PRODUCTION AND FUNDS FROM OPERATIONS AND STRONG RESERVE GROWTH FOR 2013

CALGARY, ALBERTA (March 13, 2014) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2013 (all amounts are in Canadian dollars unless otherwise noted).

“2013 was an exceptional year as Baytex delivered its highest level of funds from operations and reached a record level of annual production while growing proved plus probable reserves by 9%, all in a challenging year for heavy oil pricing. We replaced 234% of our production through organic development and generated a strong 1.8x recycle ratio,” commented James Bowzer, President and Chief Executive Officer.

Bowzer said, “We look forward to continuing our strong performance with the expansion of our asset portfolio into the Eagle Ford through the pending acquisition of Aurora Oil & Gas Limited. We are committed to a growth-and-income model and its three fundamental principles: delivering organic production growth, paying a meaningful dividend and maintaining capital discipline. Through the combination of an expanded inventory of high capital efficiency projects and an improved outlook for heavy oil differentials, we remain confident in our business plan going forward.”

Highlights

- Generated production of 58,304 boe/d (88% oil and NGL) in Q4/2013, an increase of 6% over Q4/2012, and record annual production of 57,196 boe/d (88% oil and NGL), an increase of 6% over 2012;
- Delivered funds from operations ("FFO") of $147.5 million ($1.18 per basic share) in Q4/2013, an increase of 16% over Q4/2012, and $604.4 million ($4.88 per share basic) in full-year 2013, an increase of 13% from 2012 and the highest level of annual FFO in company history;
- Increased proved reserves by 11% to 160 million boe (a 9% increase on a per share basis) and proved plus probable reserves by 9% to 318 million boe (a 7% increase on a per share basis);
- Replaced 234% of production through organic exploration and development activities. Inclusive of acquisitions and divestitures, replaced 227% of production;
- Recorded finding, development and acquisition ("FD&A") costs for proved plus probable reserves, including changes in future development costs ("FDC"), of $18.28/boe for 2013 and $15.65/boe for the three-year average (2011-2013);
- Realized a recycle ratio (operating netback divided by FD&A costs) based on proved plus probable reserves (including changes in FDC) of 1.8x for 2013, and 2.1x for the three-year average;
- Maintained a conservative payout ratio, net of dividend reinvestment plan (“DRIP”) participation, of 40% (56% before DRIP) in Q4/2013 and 39% (54% before DRIP) in full-year 2013;
- Ended the fourth quarter with total monetary debt of $762.1 million, representing a debt-to-FFO ratio of 1.3x based on FFO over the trailing twelve-month period; and
- Subsequent to the end of the year, entered into an agreement to acquire 100% of the shares of Aurora Oil & Gas Limited (“Aurora”) for total consideration of approximately $2.6 billion.

	Three Months Ended			Years Ended	
	December 31, 2013	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**330,712**	422,791	292,095	**1,367,459**	1,219,484
Funds from operations (1)	**147,544**	199,318	127,253	**604,438**	532,725
Per share – basic	**1.18**	1.61	1.05	**4.88**	4.44
Per share – diluted	**1.17**	1.59	1.04	**4.82**	4.37
Cash dividends declared (2)	**59,532**	61,354	55,043	**237,663**	215,184
Dividends declared per share	**0.66**	0.66	0.66	**2.64**	2.64
Net income (3)	**31,173**	87,331	31,620	**164,845**	258,631
Per share - basic	**0.26**	0.70	0.26	**1.33**	2.16
Per share - diluted	**0.25**	0.70	0.26	**1.32**	2.12
Exploration and development	**85,060**	121,484	66,686	**550,900**	418,625
Acquisitions, net of divestitures	**2,258**	2,838	131,797	**(39,082)**	(170,936)
Total oil and natural gas capital expenditures	**87,318**	124,322	198,483	**511,818**	247,689
Bank loan	**223,371**	244,651	116,394	**223,371**	116,394
Long-term debt	**459,540**	454,275	449,235	**459,540**	449,235
Working capital deficiency	**79,151**	57,703	34,197	**79,151**	34,197
Total monetary debt (4)	**762,062**	756,629	599,826	**762,062**	599,826
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**8,047**	8,366	7,739	**8,134**	7,360
Heavy oil (bbl/d)	**43,254**	44,908	40,257	**42,064**	39,447
Total oil and NGL (bbl/d)	**51,301**	53,274	47,996	**50,198**	46,807
Natural gas (mcf/d)	**42,018**	41,460	42,302	**41,989**	43,076
Oil equivalent (boe/d @ 6:1) (5)	**58,304**	60,184	55,046	**57,196**	53,986
Average prices (before hedging)					
WTI oil (US$/bbl)	**97.46**	105.82	88.18	**97.97**	94.19
WCS heavy oil (US$/bbl)	**65.26**	88.34	70.07	**72.78**	73.16
Edmonton par oil ($/bbl)	**86.25**	105.07	84.28	**93.24**	86.53
Baytex heavy oil ($/bbl) (6)	**61.89**	79.29	54.58	**65.24**	59.44
Baytex light oil and NGL ($/bbl)	**74.73**	88.63	72.02	**79.61**	74.07
Baytex total oil and NGL ($/bbl)	**63.91**	80.75	57.39	**67.57**	61.74
Baytex natural gas ($/mcf)	**3.52**	2.72	3.03	**3.32**	2.45
Baytex oil equivalent ($/boe)	**58.75**	73.36	52.37	**61.74**	55.48
CAD/USD noon rate at period end	**1.0636**	1.0285	0.9949	**1.0636**	0.9949
CAD/USD average rate for period	**1.0494**	1.0385	0.9913	**1.0299**	0.9991

COMMON SHARE INFORMATION	Three Months Ended			Years Ended	
	December 31, 2013	September 30, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
TSX					
Share price (Cdn$)					
High	**44.26**	44.44	48.35	**47.60**	59.40
Low	**40.21**	37.65	41.91	**36.37**	38.54
Close	**41.64**	42.51	42.87	**41.64**	42.87
Volume traded (thousands)	**22,585**	24,658	25,108	**105,097**	108,327
NYSE					
Share price (US$)					
High	**42.84**	43.08	49.25	**47.47**	59.50
Low	**37.78**	35.72	42.20	**34.75**	37.40
Close	**39.16**	41.27	43.24	**39.16**	43.24
Volume traded (thousands)	**3,657**	3,282	3,567	**15,071**	22,135
Common shares outstanding (thousands)	**125,392**	124,497	121,868	**125,392**	121,868

Notes:

(1) Funds from operations is a non-Generally Accepted Accounting Principles ("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, 2013.

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

(3) Net income for the year ended December 31, 2013 includes gains on divestitures of oil and gas properties of $21.0 million (2012 – gain of $172.5 million) and loss on financial instruments of $13.1 million (2012 - gain of $61.6 million).

(4) 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 unrealized gains or losses on financial derivatives, assets held for sale and liabilities related to assets held for sale)), the principal amount of long-term debt and long-term bank loan.

(5) 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.

(6) Heavy oil prices exclude condensate blending.

Operations Review

Production averaged 58,304 boe/d (88% oil and NGL) during Q4/2013, an increase of 6% over Q4/2012, and 57,196 boe/d for full-year 2013, an increase of 6% over 2012. Average annual production for 2013 represented the highest production rate in company history.

As previously reported, our transportation operations were hampered by severe winter weather during Q4/2013 which impacted our ability to deliver crude oil from the field to sales delivery points. As inventory levels reached capacity, production was curtailed by approximately 5,000 bbl/d in December.

Capital expenditures for exploration and development activities totaled $550.9 million for the full-year 2013 and included the drilling of 281 (226.8 net) wells with a 99% success rate.

Our 2014 production guidance remains unchanged at 60,000 to 62,000 boe/d with budgeted exploration and development expenditures of $485 million, and does not include the integration of the Aurora Eagle Ford acquisition which was announced on February 6, 2014 and is expected to close in late May 2014. Following closing of the acquisition, Baytex will provide revised guidance for full-year 2014.

Wells Drilled - Three Months Ended December 31, 2013

	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	22	10.2	—	—	—	—	5	5.0	—	—	27	15.2
Peace River area	11	11.0	5	5.0	—	—	—	—	—	—	16	16.0
	33	**21.2**	**5**	**5.0**	**—**	**—**	**5**	**5.0**	**—**	**—**	**43**	**31.2**
Light oil, NGL and natural gas												
Western Canada	—	—	—	—	1	1.0	—	—	—	—	1	1.0
North Dakota	—	—	—	—	—	—	—	—	—	—	—	—
Wyoming	1	0.7	—	—	—	—	—	—	—	—	1	0.7
	1	**0.7**	**—**	**—**	**1**	**1.0**	**—**	**—**	**—**	**—**	**2**	**1.7**
Total	**34**	**21.9**	**5**	**5.0**	**1**	**1.0**	**5**	**5.0**	**—**	**—**	**45**	**32.9**

Wells Drilled - Year Ended December 31, 2013

	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	142	102.5	4	4.0	—	—	8	8.0	2	2.0	156	116.5
Peace River area	41	41.0	15	15.0	—	—	31	31.0	—	—	87	87.0
	183	**143.5**	**19**	**19.0**	**—**	**—**	**39**	**39.0**	**2**	**2.0**	**243**	**203.5**
Light oil, NGL and natural gas												
Western Canada	14	11.0	—	—	3	3.0	—	—	—	—	17	14.0
North Dakota	20	8.6	—	—	—	—	—	—	—	—	20	8.6
Wyoming	1	0.7	—	—	—	—	—	—	—	—	1	0.7
	35	**20.3**	**—**	**—**	**3**	**3.0**	**—**	**—**	**—**	**—**	**38**	**23.3**
Total	**218**	**163.8**	**19**	**19.0**	**3**	**3.0**	**39**	**39.0**	**2**	**2.0**	**281**	**226.8**

Heavy Oil

In Q4/2013, heavy oil production averaged 43,254 bbl/d, an increase of 7% from Q4/2012. During Q4/2013, we drilled 38 (26.2 net) oil wells and five (5.0 net) stratigraphic and service wells on our heavy oil properties.

Production from our Peace River area properties averaged approximately 23,900 bbl/d in Q4/2013, an increase of 14% from Q4/2012. As previously reported, production at Peace River was hampered by severe winter weather during Q4/2013 which impacted our ability to deliver crude oil from the field to sales delivery points, resulting in production curtailments of approximately 5,000 bbl/d in the month of December.

In Q4/2013, we drilled 11 (11.0 net) cold horizontal producers encompassing a total of 125 laterals in the Peace River area bringing our 2013 drilling to 41 (41.0 net) wells. Our 2013 cold horizontal multi-lateral drilling program was one of the strongest in company history with average 30-day peak production rates of approximately 600 bbl/d, which is near the upper end of our expected range of 300 to 700 bbl/d.

Baytex continued to progress its thermal operations in the Cliffdale area with Pad 1 cumulative steam-oil ratio performance continuing to track our predictions. Pad 1 steaming operations were reduced in the fourth quarter due to steam generator repairs and maintenance. Pad 2, consisting of fifteen wells that were successfully drilled throughout 2013, are currently producing as planned under primary conditions to create the initial voidage required for the cyclic steam stimulation process. We expect steam injection at Pad 2 to commence in mid-2014.

The Alberta Energy Regulator ("AER") recently held a public proceeding to investigate concerns about odours and emissions associated with heavy oil production in the Peace River area. An oral proceeding was held during the last two weeks of January 2014. Baytex was an active participant in the proceeding and welcomed the opportunity to inform the public and the regulator about our efforts to improve our operations and reduce the environmental impact. The AER hearing panel is expected to issue their report and recommendations by March 31, 2014.

In our Lloydminster heavy oil area, Q4/2013 drilling included 15 (8.7 net) horizontal oil wells and seven (1.5 net) vertical oil wells, with a 100% success rate, and five (5.0 net) stratigraphic test wells. Construction of the Gemini steam-assisted gravity drainage ("SAGD") pilot project facilities continued in Q4/2013 and commissioning was completed early in January. Steam injection commenced on January 24, 2014 with first oil production projected to occur in Q2/2014.

Light Oil & Natural Gas

During Q4/2013, light oil and NGL production averaged 8,047 bbl/d (a 4% increase from Q4/2012) and natural gas production averaged 42.0 mmcf/d (essentially unchanged from Q4/2012). In our Bakken/Three Forks play in North Dakota, no drilling occurred in Q4/2013. Three previously drilled and completed wells on 1,280-acre spacing established average 30-day peak production rates of approximately 410 boe/d during Q4/2013.

Financial Review

We generated FFO of $147.5 million ($1.18 per basic share) in Q4/2013, which represented a 26% decrease from the $199.3 million generated in Q3/2013 and was the result of lower realized commodity prices and lower sales volumes. Full-year FFO was $604.4 million ($4.88 per basic share), an increase of 13% compared to 2012, and established a new company record for annual FFO. This increase was largely due to higher sales volumes and higher realized commodity prices.

The average WTI price for Q4/2013 was US$97.46/bbl, an 8% decrease from Q3/2013. The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 33% in Q4/2013, as compared to 17% in Q3/2013. The widening of the WCS differentials in the three months ended December 31, 2013 was caused by capacity restrictions on Canadian crude export pipelines in the fourth quarter of 2013, which triggered a back-up of crude in Western Canada, forcing it into storage. As a result of the weaker WCS in Q4/2013, our realized total oil and NGL price of $63.91/bbl in the fourth quarter of 2013 (inclusive of our physical hedging gains) decreased by 21% from $80.75/bbl in the third quarter of 2013.

Market conditions have recently improved with the forward market indicating a WCS average differential of approximately 23% for Q1/2014 and 21% for the remainder of this year. The improved market conditions reflect a number of positive catalysts unfolding in 2014, including increased refinery demand in the U.S. Midwest, a continued increase in crude by rail volumes and a number of pipeline capacity improvements and expansion projects.

We have taken advantage of the recent strength in WTI prices and the weaker Canadian dollar to add to our hedge portfolio. For Q1/2014, we have entered into hedges on approximately 55% of our WTI exposure at a weighted average price of US$99.31/bbl, 26% of our exposure to WCS price differentials primarily through a combination of long term physical supply contracts and rail delivery, 55% of our natural gas price exposure, and 31% 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.

As part of our hedging program, we are focusing on opportunities to further mitigate the volatility in WCS price differentials by transporting crude oil to higher value markets by rail. During the fourth quarter, approximately 21,500 bbl/d of our heavy oil volumes were delivered to market by rail, as compared to 7,500 bbl/d for full-year 2012 and 17,500 bbl/d for full-year 2013. For Q1/2014, we expect our heavy oil volumes on rail to increase to approximately 26,000 bbl/d.

Total monetary debt at December 31, 2013 was $762.1 million, representing a debt-to-FFO ratio of 1.3 times based on FFO over the trailing twelve-month period. At year-end, Baytex had $626.6 million in undrawn credit facilities and no long-term debt maturities until 2021.

Acquisition of Aurora

On February 6, 2014, Baytex entered an agreement to acquire all of the ordinary shares of Aurora for A$4.10 (Australian dollars) per share by way of a scheme of arrangement under Part 5.1 of the Corporations Act 2001 (Australia) (the "Arrangement"). The total purchase price for Aurora is estimated at $2.6 billion (including the assumption of approximately $0.7 billion of indebtedness). The acquisition enhances Baytex's growth-and-income business model, delivers production and reserves per share growth and provides attractive capital efficiencies for future investment. The acquisition is accretive to Baytex's funds from operations while maintaining a strong balance sheet.

Aurora's primary asset is 22,200 net contiguous acres in the prolific Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale. Aurora's fourth quarter 2013 gross production was 24,678 boe/d (82% liquids) of predominantly light, high-quality crude oil. The Sugarkane Field has been largely delineated with infrastructure in place which is expected to facilitate low-risk future annual production growth. In addition, these assets have significant future reserves upside potential from well downspacing, improving completion techniques and new development targets in additional zones.

The Arrangement is subject to a number of customary closing conditions, including the receipt of required regulatory approvals and court approvals, as well as the approval of the shareholders of Aurora. Regulatory approvals include approval of the

Australian Foreign Investment Review Board and the applicable approvals required under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 ("HSR"), as amended. On March 4, 2014, we received approval from the United States Federal Trade Commission with respect to HSR. The Arrangement must be approved by: (i) at least 75% of the votes cast by Aurora shareholders; and (ii) by a majority, in number, of the Aurora shareholders who cast votes. The Arrangement is expected to close in late May 2014.

To finance the acquisition of Aurora, Baytex completed a subscription receipt financing on February 24, 2014, raising gross proceeds of approximately $1.5 billion, and entered into a commitment letter with a Canadian chartered bank for the provision of new revolving credit facilities in the amount of $1.0 billion (to replace the $850 million revolving credit facilities of Baytex Energy) and a new two-year $200 million non-revolving loan. Baytex has also entered into a commitment letter with a Canadian chartered bank for the provision of a new borrowing base facility in the amount of US$300 million for a U.S. subsidiary of Aurora (to be established upon closing of the Arrangement as a replacement for Aurora's existing facility).

9% Dividend Increase

At Baytex, we are committed to a growth-and-income model and its three fundamental principles: delivering organic production growth, paying a meaningful dividend and maintaining capital discipline. Through the combination of an expanded inventory of high capital efficiency projects and an improved outlook for heavy oil differentials, we remain confident in our business plan going forward. Consequently, Baytex has committed to increase the monthly dividend on its common shares by 9% to $0.24 from $0.22 per share, subject to the completion of the Aurora acquisition.

Year-end 2013 Reserves

Baytex's year-end 2013 reserves were evaluated by Sproule Associates Limited ("Sproule"), the independent qualified 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"). 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. Finding and development ("F&D") and finding, development and acquisition costs are all reported inclusive of future development costs. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2013, which will be filed in late March 2014.

Highlights of the 2013 reserve report include:

- Proved reserves increased 11% to 160 million boe (a 9% increase on a per share basis) and proved plus probable reserves increased 9% to 318 million boe (a 7% increase on a per-share basis). Year-end 2013 proved plus probable reserves are comprised of 90% oil and NGLs and 10% natural gas;
    - At Peace River, proved plus probable reserves attributable to our conventional heavy oil development in the Bluesky formation (cold horizontal multi-lateral wells) increased 6% to 67 million barrels. Our 2013 drilling program included 41.0 net multi-lateral wells;
    - At Lloydminster, proved plus probable reserves total 59 million barrels, essentially unchanged from year-end 2012, as reserve additions offset production. In 2013, we drilled 104.5 net wells (54% vertical wells, 46% horizontal wells) in the Lloydminster region with a 98% success rate;
    - In our Bakken/Three Forks resource play, proved plus probable reserves increased 55% to 53.5 million barrels of oil equivalent due largely to an increased drilling density of five wells (previously three wells) per 1,280 acre spacing unit. Our 2013 drilling program included 8.6 net wells; and
    - Bitumen reserves on a proved plus probable basis total 102 million barrels, unchanged from year-end 2012. During 2013, we continued to progress thermal development with facility construction at both our 15-well CSS module at Cliffdale and our Gemini SAGD pilot project;
- Exploration and development capital expenditures in 2013 totaled $550.9 million. Net of property dispositions of $39.1 million, the total net capital outlay in 2013 was $511.8 million. This level of net expenditures resulted in the net addition of 47.4 million boe of proved plus probable reserves;
- We replaced 234% of production through exploration and development activities (excluding acquisitions and divestitures) with F&D costs of $19.30/boe. Three-year average (2011-2013) F&D costs are $19.34/boe;
- Inclusive of acquisitions and divestitures, we replaced 227% of production with FD&A costs of $18.28/boe. Three-year average (2011-2013) FD&A costs are $15.65/boe;
- The net present value (before income taxes and discounted at 10%) of future net revenue attributable to our proved plus probable reserves increased 15% to $4.3 billion;

- Baytex generated an operating netback of $32.62/boe (excluding financial derivatives) resulting in a proved plus probable recycle ratio of 1.8x. Three-year average (2011-2013) recycle ratio is 2.1x; and

- Proved plus probable reserves life index increased to 14.3 years from 14.0 years based on the mid-point of our 2014 production guidance of 61,000 boe/d.

Petroleum and Natural Gas Reserves as at December 31, 2013

The following table sets forth our gross and net reserve volumes at December 31, 2013 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	41,526	30,985	7,422	6,719	10,129	7,958
Developed Non-Producing	8,944	7,404	3,491	3,083	28	24
Undeveloped	32,433	26,757	8,409	7,336	25,792	21,021
Total Proved	82,903	65,146	19,322	17,139	35,949	29,003
Probable	42,644	34,141	82,564	66,117	16,765	13,474
Total Proved Plus Probable	125,547	99,287	101,886	83,256	52,714	42,477

	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	2,032	1,461	56,083	47,238	70,456	54,997
Developed Non-Producing	75	55	1,825	1,572	12,842	10,827
Undeveloped	965	675	51,757	40,936	76,226	62,611
Total Proved	3,073	2,191	109,665	89,745	159,524	128,436
Probable	3,469	2,421	78,895	60,721	158,591	126,273
Total Proved Plus Probable	6,542	4,611	188,561	150,466	318,115	254,709

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

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

	Heavy Oil			Bitumen		
Gross Reserves Category	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)
December 31, 2012	79,843	42,021	121,863	19,476	82,085	101,562
Extensions	19,212	5,865	25,078	560	240	800
Discoveries	10	6	17	—	—	—
Improved Recoveries	243	888	1,131	—	—	—
Technical Revisions	(2,535)	(6,609)	(9,145)	56	233	289
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	581	473	1,053	132	6	138
Production	(14,451)	—	(14,451)	(903)	—	(903)
December 31, 2013	82,903	42,644	125,547	19,322	82,564	101,886

	Light and Medium Crude Oil			Natural Gas Liquids		
Gross Reserves Category	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)	Proved (mbbl)	Probable (mbbl)	Proved + Probable (mbbl)
December 31, 2012	25,119	14,079	39,199	5,788	3,424	9,212
Extensions	16,514	6,075	22,589	262	1,739	2,001
Discoveries	—	—	—	—	—	—
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	(2,404)	(3,184)	(5,588)	(2,234)	(1,760)	(3,994)
Acquisitions	—	—	—	—	—	—
Dispositions	(1,156)	(379)	(1,535)	—	—	—
Economic Factors	179	173	352	(77)	66	(11)
Production	(2,303)	—	(2,303)	(666)	—	(666)
December 31, 2013	35,949	16,765	52,714	3,073	3,469	6,542

	Natural Gas			Oil Equivalent [3]		
Gross Reserves Category	Proved (mmcf)	Probable (mmcf)	Proved + Probable (mmcf)	Proved (mboe)	Probable (mboe)	Proved + Probable (mboe)
December 31, 2012	79,308	39,257	118,565	143,444	148,152	291,597
Extensions	27,745	41,382	69,127	41,172	20,817	61,989
Discoveries	—	—	—	10	6	17
Improved Recoveries	—	—	—	243	888	1,131
Technical Revisions	20,051	(3,080)	16,971	(3,776)	(11,833)	(15,609)
Acquisitions	—	—	—	—	—	—
Dispositions	(22)	(4)	(26)	(1,160)	(379)	(1,540)
Economic Factors	(2,091)	1,341	(750)	466	941	1,407
Production	(15,326)	—	(15,326)	(20,877)	—	(20,877)
December 31, 2013	109,665	78,895	188,561	159,524	158,592	318,115

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, 2013 and 2012 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 proved and proved plus probable reserves at year-end 2013 and the mid-point of our 2014 production guidance of 61,000 boe/d.

	Mid-Point of 2014	Reserve Life Index (years)	
	Production Guidance	Proved	Proved Plus Probable
Oil and NGL (bbl/d)	54,300	7.1	14.5
Natural Gas (mcf/d)	40,200	7.5	12.8
Oil Equivalent (boe/d)	61,000	7.2	14.3

Capital Program Efficiency

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

	2013	2012	2011	Three-Year Total / Average 2011 - 2013
Capital Expenditures ($millions)				
Exploration and development	**$ 550.9**	$ 418.6	$ 367.9	**$ 1,337.4**
Acquisitions (net of dispositions)	**(39.1)**	(170.9)	148.8	**(61.2)**
Total	**$ 511.8**	$ 247.7	$ 516.6	**$ 1,276.1**
Change in Future Development Costs ($millions)				
Proved	**$ 261.5**	$ (50.1)	$ 315.4	**$ 526.8**
Proved plus probable	**$ 354.3**	$ 433.5	$ 253.3	**$ 1,041.1**
Proved Reserve Additions (mboe)				
Exploration and development	**38,117**	18,411	27,151	**83,679**
Acquisitions (net of dispositions)	**(1,160)**	(11,769)	7,519	**(5,410)**
Total	**36,957**	6,642	34,670	**78,269**
Proved plus Probable Reserve Additions (mboe)				
Exploration and development	**48,936**	33,659	30,033	**112,628**
Acquisitions (net of dispositions)	**(1,540)**	25,523	11,415	**35,398**
Total	**47,396**	59,182	41,448	**148,027**
F&D costs ($/boe) (1)				
Proved	**$ 22.34**	$ 29.14	$ 23.66	**$ 24.26**
Proved plus probable	**$ 19.30**	$ 19.69	$ 19.02	**$ 19.34**
FD&A costs ($/boe)				
Proved	**$ 20.92**	$ 29.75	$ 24.00	**$ 23.03**
Proved plus probable	**$ 18.28**	$ 11.51	$ 18.57	**$ 15.65**
Ratios (based on proved plus probable reserves)				
Production replacement (2)	**227%**	300%	227%	**251%**
Recycle ratio (3)	**1.8x**	2.7x	1.9x	**2.1x**

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 F&D costs related to reserve additions for that year.

(2) Production Replacement ratio is calculated as total reserve additions (including acquisitions and divestitures) divided by annual production.

(3) Recycle ratio is calculated as operating netback divided by FD&A costs (proved plus probable including 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). Please note that the data in the table may not add due to rounding.

	Summary of Net Present Value of Future Net Revenue As at December 31, 2013 Before Income Taxes and Discounted at (%/year) Forecast Prices and Costs				
Reserve Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 2,132,314	$ 1,800,435	$ 1,572,541	$ 1,406,143	$ 1,279,038
Developed Non-Producing	396,448	310,251	249,035	204,183	170,432
Undeveloped	2,181,190	1,435,733	987,618	703,083	512,882
Total Proved	4,709,952	3,546,419	2,809,194	2,313,409	1,962,352
Probable	4,787,326	2,511,052	1,500,585	976,906	673,069
Total Proved Plus Probable	$ 9,497,278	$ 6,057,470	$ 4,309,779	$ 3,290,315	$ 2,635,421

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, 2013 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, 2013.

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 $US/$Cdn
2013 act.	97.98	93.24	74.20	3.13	0.8	0.971
2014	94.65	92.64	77.81	4.00	1.5	0.940
2015	88.37	89.31	75.02	3.99	1.5	0.940
2016	84.25	89.63	75.29	4.00	1.5	0.940
2017	95.52	101.62	85.36	4.93	1.5	0.940
2018	96.96	103.14	86.64	5.01	1.5	0.940
2019	98.41	104.69	87.94	5.09	1.5	0.940
2020	99.89	106.26	89.26	5.18	1.5	0.940
2021	101.38	107.86	90.60	5.26	1.5	0.940
2022	102.91	109.47	91.96	5.35	1.5	0.940
2023	104.45	111.12	93.34	5.43	1.5	0.940
2024	106.02	112.79	94.74	5.52	1.5	0.940
Thereafter			Escalation rate of 1.5%			

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)
2014	$ 262,175	$ 384,056
2015	362,214	528,549
2016	188,471	414,661
2017	306,304	422,621
2018	127,209	246,945
Remaining	67,831	269,952
Total (Undiscounted)	$ 1,314,204	$ 2,266,786

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2013.

	Undeveloped Acres	
	Gross	**Net**
Canada		
Alberta	591,159	512,682
British Columbia	38,239	29,629
Saskatchewan	178,918	169,934
Total Canada	808,316	712,245
United States		
New Mexico	14,313	14,313
North Dakota	39,845	23,610
Wyoming	100,542	63,983
Total United States	154,700	101,906
Total Company	963,016	814,151

We estimate the value of our net undeveloped land holdings at December 31, 2013 to be approximately $282 million. This internal evaluation generally represents the estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown and State land sales for the properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries.

Contingent Resource Assessment

We commissioned Sproule to conduct an assessment of contingent resources effective December 31, 2013 on two of our oil resource plays: the Bluesky in the Peace River area of Alberta, and the Bakken/Three Forks in North Dakota. We did not request Sproule to prepare an update of the estimate of contingent resource in the Lower Cretaceous Mannville Group for the Gemini Thermal Project as no developments had occurred that would have caused a change in the estimate made effective December 31, 2012. We also commissioned McDaniel & Associates Consultants Ltd. ("McDaniel") to conduct an assessment of contingent resource effective December 31, 2013 on the Lower Cretaceous Mannville Group in northeast Alberta.

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. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

For the total of these four plays, Sproule and McDaniel's estimate of contingent resource ranges from 612 million barrels of oil equivalent and bitumen in the "low estimate" (C1) to 1,181 million barrels of oil equivalent and bitumen in the "high estimate" (C3), with a "best estimate" (C2) of 798 million barrels of oil equivalent and bitumen. Contingent resources are in addition to currently booked reserves.

The best estimate contingent resource of 798 million barrels of oil equivalent and bitumen is largely unchanged from year-end 2012. The best estimate contingent resource for Bakken/Three Forks of 34 million barrels of oil equivalent represents a 26% increase over year-end 2012, and is largely attributable to reduced well spacing. Notable changes to our Bakken/Three Forks contingent resource assessment include land adjustments, transfer of reserves to contingent resource and the conversion of contingent resource to reserves during the year.

The table below summarizes the Sproule and McDaniel estimates of economic contingent resource for the four plays by geographic area. The contingent resource assessments were prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook and NI 51-101.

(millions of barrels of oil equivalent and bitumen)[3]	As of Date	Economic Contingent Resources (gross)[(1)(2)(4)(5)]		
		Low[(6)]	Best[(7)]	High[(8)]
Peace River, Alberta	December 31, 2013	450	553	796
Northeast Alberta	December 31, 2013	66	125	196
Gemini Thermal Project - Cold Lake, Alberta	December 31, 2012	78	87	127
Bakken/Three Forks - North Dakota, USA	December 31, 2013	19	34	63
Total		612	798	1,181

Notes:

(1) Contingent resource is defined in the Canadian Oil and Gas Evaluation 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. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

(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 the Gemini Thermal Project 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) 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. The total volumes presented in the table are arithmetic sums of multiple estimates of contingent resource, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of contingent resource and appreciate the differing probabilities of recovery associated with each class as explained herein.

(5) 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 ended December 31, 2013 and the audited consolidated financial statements for the year ended December 31, 2013 and the related Management's Discussion and Analysis of the operating and financial results can be accessed immediately on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Today
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call today, March 13, 2014, starting at 9:00am MDT (11:00am EDT). To participate, please dial 416-340-8527 or toll free in North America 1-800-766-6630 and toll free international 1-800-2787-2090. Alternatively, to listen to the conference call online, please enter http://www.gowebcasting.com/5287 in your web browser.

An archived recording of the conference call will be available until March 20, 2014 by dialing toll free 1-800-408-3053 within North America (Toronto local dial 905-694-9451, International toll free 1-800-3366-3052) and entering reservation code 7295600. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to: our business strategies, plans and objectives; our average production rate for 2014; our exploration and development capital expenditures for 2014; expected average 30-day peak production rates from cold horizontal multi-lateral wells at Peace River; our Cliffdale cyclic steam stimulation project, including our assessment of the performance of Pad 1 and the timing of commencing steam injection at Pad 2; the timing of the release of the final report and recommendations from the AER's public proceeding into concerns about odours and emissions associated with heavy oil production in the Peace River area; the timing of first oil production from our Gemini steam-assisted gravity drainage project; 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 2014; our debt-to-FFO ratio; our liquidity and financial capacity; the sufficiency of our financial resources to fund our operations; the anticipated benefits from the acquisition of Aurora, including our beliefs that the acquisition will be an excellent fit with our business model and will provide shareholders with exposure to low-risk, repeatable, high-return projects with capital efficiencies; our expectations that the Aurora assets have infrastructure in place that support low-risk future annual production and that such assets will provide material production, long-term growth and high quality reserves with upside potential; anticipated effect of the acquisition of Aurora on us, including our funds from operations; our expectations regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the Aurora assets; the timing of completion of the acquisition of Aurora; our plans to establish new revolving credit facilities and a term loan for us and a borrowing base facility for Aurora's U.S. subsidiary following closing of the Arrangement; payment of the purchase price for the acquisition of Aurora, including the use of proceeds from the subscription receipt financing and our plans to draw on the new revolving credit facilities and term loan; our plan to increase the dividend on our common shares upon completion of the acquisition of Aurora; our reserve life index; forecast prices for oil and natural gas; forecast interest and exchange rates; future development costs; and the value of our undeveloped land holdings. 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 funds from operations 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: the receipt of regulatory, court and shareholder approvals for the Arrangement; our ability to execute and realize on the anticipated benefits of the acquisition of Aurora; petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oil; 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 for our operating activities; 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; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). 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: the acquisition of Aurora may not be completed on the terms contemplated or at all; failure to realize the anticipated benefits of the acquisition of Aurora; closing of the acquisition of Aurora could be delayed or not completed if we are unable to obtain the necessary regulatory, court and shareholder approvals for the Arrangement or any other approvals required for completion or, unless waived, some other condition to closing is not satisfied; failure to put in place a borrowing base facility for Aurora's U.S. subsidiary following completion of the Arrangement; declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; access to external sources of capital; third party credit risk; a downgrade of our credit ratings; risks associated with the exploitation of our properties and our ability to acquire reserves; increases in operating costs; changes in government regulations that affect the oil and gas industry; changes to royalty or mineral/severance tax regimes; risks relating to hydraulic fracturing; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with properties operated by third parties; risks associated with delays in business operations; risks associated with the marketing of our petroleum and natural gas production; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; expansion of our operations; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the activities of our operating entities and their key personnel and information systems; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonal weather patterns; our permitted investments; access to technological advances; changes in the demand for oil and natural gas products; involvement in legal, regulatory and tax proceedings; the failure of third parties to comply with confidentiality agreements; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and 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 the control of Baytex. These 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, 2012, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

The above summary of assumptions and risks related to forward-looking statements in this press release has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations (if the acquisition of Aurora is completed) and such information may not be appropriate for other purposes. 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, 2013, which will be filed later in March 2014. Listed below are cautionary statements that are specifically required by NI 51-101:

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

- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to 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, 2013 of the volumes of the "contingent resource" for our oil resource plays in the Bluesky in the Peace River area of Alberta, the Mannville group in northeast Alberta and the Bakken/Three Forks in North Dakota and as of December 31, 2012 for the Gemini Thermal Project in Cold Lake, Alberta. 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; 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.

References herein to average 30-day peak production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the acquired assets. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

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 88% 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. The subscription receipts issued by Baytex to fund a portion of the purchase price for Aurora Oil & Gas Limited trade on the Toronto Stock Exchange under the symbol BTE.R.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

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