BAYTEX ENERGY CORP.

Q2 REPORT 2013

SUMMARY

- Produced a record 58,236 boe/d (87% oil and NGL) in Q2/2013, an increase of 12% over Q1/2013;
- Generated funds from operations ("FFO") of $155.8 million ($1.26 per basic share) during Q2/2013, an increase of 53% over Q1/2013;
- Drilled 17 multi-lateral wells at Peace River, achieving average 30-day peak production rates of approximately 700 bbl/d;
- Drilled 63 net wells in our Lloydminster area through the first six months of 2013 with a 98% success rate, including one successful thermal infill well at our Kerrobert steam-assisted gravity drainage project;
- Continued to progress our thermal development with facility construction now underway at both our Cliffdale 15-well cyclic steam stimulation module and our steam-assisted gravity drainage pilot project at Angling Lake;
- Realized an operating netback (sales price less royalties, production and operating expenses and transportation expenses) in Q2/2013 of $31.71/boe, an increase of 27% over Q1/2013; and
- Ended the second quarter with total monetary debt of $770.5 million, representing a debt-to-FFO ratio of 1.2 times based on Q2/2013 FFO annualized.

	Three Months Ended			Six Months Ended	
	June 30, 2013	March 31, 2013	June 30, 2012	**June 30, 2013**	June 30, 2012
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**341,011**	272,945	284,248	**613,956**	627,603
Funds from operations[1]	**155,804**	101,772	124,692	**257,576**	266,428
Per share – basic	**1.26**	0.83	1.04	**2.09**	2.24
Per share – diluted	**1.25**	0.82	1.03	**2.07**	2.20
Cash dividends declared[2]	**60,326**	56,449	51,943	**116,775**	107,502
Dividends declared per share	**0.66**	0.66	0.66	**1.32**	1.32
Net income	**36,192**	10,149	157,280	**46,341**	200,238
Per share – basic	**0.29**	0.08	1.32	**0.37**	1.68
Per share – diluted	**0.29**	0.08	1.30	**0.37**	1.66
Exploration and development	**177,834**	166,522	102,895	**344,356**	238,813
Property acquisitions	**54**	–	10,173	**54**	12,509
Proceeds from divestitures	**(1,850)**	(42,382)	(313,834)	**(44,232)**	(317,402)
Total oil and natural gas capital expenditures	**176,038**	124,140	(200,766)	**300,178**	(66,080)
Bank loan	**225,434**	155,842	396,207	**225,434**	396,207
Long-term debt	**457,680**	452,340	302,865	**457,680**	302,865
Working capital deficiency (surplus)	**87,418**	77,980	(261,153)	**87,418**	(261,153)
Total monetary debt[3]	**770,532**	686,162	437,919	**770,532**	437,919

	Three Months Ended			Six Months Ended	
	June 30, 2013	March 31, 2013	June 30, 2012	June 30, 2013	June 30, 2012
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	8,202	7,920	7,090	8,062	7,327
Heavy oil (bbl/d)	42,510	37,486	38,579	40,012	38,467
Total oil and NGL (bbl/d)	50,712	45,406	45,669	48,074	45,794
Natural gas (mcf/d)	45,148	39,305	44,426	42,243	44,757
Oil equivalent (boe/d @ 6:1)(4)	58,236	51,957	53,073	55,115	53,254
Average prices (before hedging)					
WTI oil (US$/bbl)	94.22	94.37	93.49	94.30	98.20
WCS heavy oil (US$/bbl)	75.07	62.41	70.62	68.75	76.06
Edmonton par oil ($/bbl)	92.94	88.65	84.42	90.77	88.55
Baytex light oil and NGL ($/bbl)	77.85	76.72	71.62	77.30	76.97
Baytex heavy oil ($/bbl)(5)	63.92	53.47	57.42	59.07	61.65
Baytex total oil and NGL ($/bbl)	66.17	58.00	59.63	62.12	64.10
Baytex natural gas ($/mcf)	3.59	3.46	2.00	3.53	2.23
Baytex oil equivalent ($/boe)	60.42	52.89	52.97	56.90	57.00
CAD/USD noon rate at period end	1.0512	1.0156	1.0191	1.0512	1.0191
CAD/USD average rate for period	1.0231	1.0089	1.0102	1.0159	1.0052
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	43.05	47.60	53.61	47.60	59.40
Low	36.37	42.00	38.54	36.37	38.54
Close	37.90	42.57	42.89	37.90	42.89
Volume traded (thousands)	30,085	27,768	34,162	57,853	57,540
NYSE					
Share price (US$)					
High	42.50	47.47	54.44	47.47	59.50
Low	34.71	41.04	37.40	34.71	37.40
Close	36.04	41.93	42.11	36.04	42.11
Volume traded (thousands)	4,763	3,369	8,257	8,132	12,745
Common shares outstanding (thousands)	123,593	122,874	119,914	123,593	119,914

Notes:

(1) 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 finance costs, changes in non-cash operating working capital and other operating items. Baytex's determination of 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 and six months ended June 30, 2013.

(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 unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loan.

(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.

Advisory Regarding Forward-Looking Statements

This report contains forward-looking statements relating to: our operating and financial results in the second half of 2013; our average production rate for 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 remainder of 2013 and, in some cases, when such wells will commence production; initial production rates from wells drilled; our Peace River heavy oil area, including our assessment of the productivity of recently drilled horizontal wells; our Cliffdale cyclic steam stimulation project, including our assessment of the steam and flowback operations for the initial 10-well module and our plan for a second module, including the timing of drilling the wells, completing plant construction, commencing cold production and commencing steam injection; our plans for a steam-assisted gravity drainage pilot project at Angling Lake, including the timing of construction of the pilot facilities, drilling of the pilot well pair and commencing steam injection; the outlook for Canadian heavy oil prices and the pricing differential between Canadian heavy oil and West Texas Intermediate light oil; the ability to access the U.S. Gulf Coast market by transporting crude oil on rail; 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 the volatility in heavy oil price differentials by transporting our crude oil to market by rail; the volume of heavy oil to be transported to market on rail for the third quarter of 2013; our average royalty rate for full-year 2013; our debt-to-FFO ratio; the amount of our undrawn credit facilities at June 30, 2013; our liquidity and financial capacity; and the potential to reduce total debt levels over the balance of 2013. 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. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking information and statements.

Non-GAAP Financial Measures

Funds from operations is not a measurement based on 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 sales price less royalties, production and operating expenses and transportation expenses divided 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.

Total monetary debt is not a measurement based on GAAP in Canada. Baytex defines total monetary debt as 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)), the principal amount of long-term debt and long-term bank loans. Baytex believes that this measure assists in providing a more complete understanding of our cash liabilities.

MESSAGE TO SHAREHOLDERS

Operations Review

Production averaged 58,236 boe/d (87% oil and NGL) during Q2/2013, an increase of 12% over Q1/2013. Capital expenditures for exploration and development activities totaled $177.8 million and included the drilling of 33 (25.8 net) wells with a 100% success rate. In addition, we continued to progress our thermal development with facility construction now underway at both our Cliffdale 15-well cyclic steam stimulation module and our steam-assisted gravity drainage pilot project at Angling Lake.

In recognition of our strong operating results to-date, we are tightening our production guidance range for 2013 from the previously disclosed range of 56,000-58,000 boe/d to 57,000-58,000 boe/d. Consistent with previous guidance, exploration and development expenditures for 2013 are forecast to be approximately $520 million, which includes $90 million for long-term thermal projects. 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 June 30, 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	6	3.6	–	–	–	–	–	–	–	–	6	3.6
Peace River area	17	17.0	–	–	–	–	–	–	–	–	17	17.0
	23	**20.6**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**23**	**20.6**
Light oil, NGL and natural gas												
Western Canada	2	0.7	–	–	–	–	–	–	–	–	2	0.7
North Dakota	8	4.5	–	–	–	–	–	–	–	–	8	4.5
	10	**5.2**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**10**	**5.2**
Total	**33**	**25.8**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**33**	**25.8**

Wells Drilled – Six Months Ended June 30, 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	73	61.3	1	1.0	–	–	–	–	1	1.0	75	63.3
Peace River area	23	23.0	–	–	–	–	30	30.0	–	–	53	53.0
	96	**84.3**	**1**	**1.0**	**–**	**–**	**30**	**30.0**	**1**	**1.0**	**128**	**116.3**
Light oil, NGL and natural gas												
Western Canada	14	11.0	–	–	1	1.0	–	–	–	–	15	12.0
North Dakota	15	7.3	–	–	–	–	–	–	–	–	15	7.3
	29	**18.3**	**–**	**–**	**1**	**1.0**	**–**	**–**	**–**	**–**	**30**	**19.3**
Total	**125**	**102.6**	**1**	**1.0**	**1**	**1.0**	**30**	**30.0**	**1**	**1.0**	**158**	**135.6**

Heavy Oil

In Q2/2013, heavy oil production averaged 42,510 bbl/d, an increase of 13% over Q1/2013. During Q2/2013, we drilled 23 (20.6 net) oil wells with a success rate of 100%.

Production from our Peace River area properties averaged approximately 23,000 bbl/d in Q2/2013, an increase of 22% over Q1/2013. In the second quarter of 2013, we drilled 17 (17.0 net) cold horizontal producers in the Peace River area bringing our year-to-date drilling to 23 (23.0 net) wells. Of the 23 wells drilled during the first half of 2013, 22 wells have established average 30-day peak production rates of approximately 700 bbl/d. We plan to drill approximately 14 multi-lateral horizontal wells in the remainder of 2013.

Successful operations continued at our Cliffdale 10-well cyclic steam stimulation ("CSS") module with Q2/2013 production averaging approximately 400 bbl/d. During the second quarter, fifth cycle steaming operations commenced on the initial Cliffdale pilot well with production flowback start-up in mid-June. Current production from the Cliffdale CSS project is approximately 700 bbl/d. Facility construction at our new Cliffdale 15-well CSS module is well underway with drilling operations commencing in Q2/2013. We expect to complete construction of the plant and commence cold production in Q4/2013. First cycle steaming of the wells is expected to occur in the first half of 2014.

In our Lloydminster heavy oil area, Q2/2013 drilling included four (1.6 net) horizontal oil wells and two (2.0 net) vertical oil wells. During Q1/2013, we drilled one (1.0 net) thermal infill well at our Kerrobert steam-assisted gravity drainage ("SAGD") project. This well commenced production in Q2/2013 adding incremental production of approximately 400 bbl/d. We plan to drill approximately 50 net wells in the Lloydminster area in the remainder of 2013, including one thermal infill well and one SAGD well pair at Kerrobert.

At Angling Lake, construction of the Gemini SAGD pilot project facilities commenced late in Q2/2013. Construction of the drilling pad is complete, mechanical crews have been mobilized and major equipment is being moved onsite. We expect to drill the SAGD well pair during the third quarter and are on track for steaming late this year or early 2014.

Light Oil & Natural Gas

During Q2/2013, light oil, NGL and natural gas production increased 9% over Q1/2013 to 15,726 boe/d, which was comprised of 8,202 bbl/d of light oil and NGL and 45.1 mmcf/d of natural gas.

In our Bakken/Three Forks play in North Dakota, we drilled eight (4.5 net) operated horizontal oil wells and fracture-stimulated 10 (5.1 net) operated wells in Q2/2013. During Q2/2013, nine Baytex-operated wells on 1,280-acre spacing established average 30-day peak production rates of approximately 360 boe/d. We plan to drill approximately two (1.0 net) wells on our Bakken/Three Forks play in North Dakota in the remainder of 2013.

Financial Review

We generated FFO of $155.8 million ($1.26 per basic share) in Q2/2013, which was the second highest level of quarterly FFO in company history. This represents a 53% increase from the $101.8 million generated in Q1/2013. This increase was the result of higher sales volumes and higher realized commodity prices. During the second quarter, our operating netback (sales price less royalties, production and operating expenses and transportation expenses) of $31.71/boe represented an improvement of 27% over Q1/2013.

The average WTI price for Q2/2013 was US$94.22/bbl, essentially unchanged from Q1/2013. The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 20% in Q2/2013, as compared to 34% in Q1/2013. Factors that caused heavy oil differentials to narrow included heavy oil supply shortfalls, declines in Canadian crude storage levels, increases in rail shipments and the return of refineries from maintenance. As a result of narrower heavy oil differentials, our realized average oil and NGL price of $66.17/bbl in Q2/2013 (inclusive of our physical hedging gains) increased by 14% from $58.00/bbl in Q1/2013.

We have taken advantage of the recent strength in WTI prices and the weaker Canadian dollar to add to our hedge portfolio. For the second half of 2013, we have entered into hedges on approximately 63% of our WTI exposure at a weighted average price of US$99.33/bbl, 42% of our exposure to WCS heavy oil differentials through a combination of long term physical supply contracts and rail delivery, 54% of our natural gas price exposure, and 51% 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 second quarter, approximately 17,000 bbl/d of our heavy oil volumes were delivered to market by rail, as compared to 7,500 bbl/d for full-year 2012. For Q3/2013, we expect to deliver approximately 20,000 bbl/d of our heavy oil volumes by rail, and we continue to explore additional opportunities for rail deliveries.

Royalty rates in Q2/2013 were approximately 19.3% of sales revenues before sales of purchased condensate. We expect royalty rates to average approximately 20-21% for full-year 2013 as a result of certain oil sands projects reaching payout and farm-in agreements.

Total monetary debt at the end of Q2/2013 was $770.5 million, representing a debt-to-FFO ratio of 1.2 times based on Q2/2013 FFO annualized. At the end of the second quarter, Baytex had $624.6 million in undrawn credit facilities and no long-term debt maturities until 2021. During the second quarter, we increased the amount of our credit facilities by $150 million to $850 million and extended the maximum term of the facilities by one year to four years. With our capital spending program weighted toward the first half of the year, and assuming continued strength in production levels and commodity prices, we expect that total debt levels will reduce over the balance of 2013.

Conclusion

Baytex's operational execution remains on track with capital spending progressing as planned in our key development areas. We grew production in the second quarter by 12% to over 58,000 boe/d, which represents the highest quarterly production rate in company history. Our FFO of $155.8 million represents the second highest level of quarterly FFO. We expect continued strong operating and financial results in the second half of this year and in recognition of this, we are tightening our production guidance range for 2013 from the previously disclosed range of 56,000-58,000 boe/d to 57,000-58,000 boe/d. Our balance sheet remains in excellent shape with significant undrawn credit facilities. Utilizing our substantial resource base, we will continue to execute our growth-and-income business model.

We want to express our appreciation for your continued support as we move forward in executing our plan for long-term value creation.

On behalf of the Board of Directors,

James L. Bowzer
President and Chief Executive Officer
August 14, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and six months ended June 30, 2013. This information is provided as of August 13, 2013. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The second quarter results have been compared with the corresponding period in 2012. This MD&A should be read in conjunction with the Company's condensed interim unaudited consolidated financial statements ("consolidated financial statements") for the three and six months ended June 30, 2013, its audited consolidated financial statements for the years ended December 31, 2012 and 2011, together with accompanying notes, and its Annual Information Form for the year ended December 31, 2012. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, 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, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as funds from operations, payout ratio, total monetary debt and operating netback) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, payout ratio and operating netback are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers.

Funds from Operations

We define funds from operations as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. However, funds from operations should not be construed as an alternative to traditional performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income. For a reconciliation of funds from operations to cash flow from operating activities, see "Funds from Operations, Payout Ratio and Dividends".

Payout Ratio

We define payout ratio as cash dividends (net of participation in our dividend reinvestment plan) divided by funds from operations. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments.

Total Monetary Debt

We define total monetary debt as 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)), the principal amount of long-term debt and long-term bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Operating Netback

We define operating netback as product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. As sales volumes are not materially different than production volumes, we believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

RESULTS OF OPERATIONS

Production

	Three Months Ended June 30			Six Months Ended June 30		
	2013	2012	Change	**2013**	2012	Change
Daily Production						
Light oil and NGL (bbl/d)	**8,202**	7,090	16%	**8,062**	7,327	10%
Heavy oil (bbl/d)[1]	**42,510**	38,579	10%	**40,012**	38,467	4%
Natural gas (mcf/d)	**45,148**	44,426	2%	**42,243**	44,757	(6%)
Total production (boe/d)	**58,236**	53,073	10%	**55,115**	53,254	3%
Production Mix						
Light oil and NGL	**14%**	13%	–	**14%**	14%	–
Heavy oil	**73%**	73%	–	**73%**	72%	–
Natural gas	**13%**	14%	–	**13%**	14%	–

(1) *Heavy oil sales volumes may differ from reported production volumes due to changes to Baytex's heavy oil inventory. For the three months ended June 30, 2013, heavy oil sales volumes were 204 bbl/d higher than production volumes (three months ended June 30, 2012 – 88 bbl/d lower). For the six months ended June 30, 2013, heavy oil sales volumes were 97 bbl/d higher than production volumes (six months ended June 30, 2012 – 1 bbl/d higher).*

Production for the three months ended June 30, 2013 averaged 58,236 boe/d, compared to 53,073 boe/d for the same period in 2012, a 10% increase. Light oil and natural gas liquids ("NGL") production in the second quarter of 2013 increased by 16% to 8,202 bbl/d, as compared to 7,090 bbl/d in the second quarter of 2012, primarily due to successful development activities in the U.S., partially offset by the sale of 950 bbl/d associated with our non-operated position in North Dakota in the second quarter of 2012. Heavy oil production for the second quarter of 2013 increased by 10% to 42,510 bbl/d from 38,579 bbl/d in the second quarter of 2012 primarily due to successful development in the Peace River area. Natural gas production increased by 2% to 45.1 mmcf/d for the second quarter of 2013, as compared to 44.4 mmcf/d for the same period in 2012, primarily due to successful drilling results in the Pembina region of Alberta.

Production for the six months ended June 30, 2013 averaged 55,115 boe/d, compared to 53,254 boe/d for the same period in 2012, a 3% increase. Light oil and NGL production in the first six months of 2013 increased by 10% to 8,062 bbl/d, as compared to 7,327 bbl/d in the first six months of 2012, primarily due to successful development activities in the U.S., partially offset by the sale of 950 bbl/d associated with our non-operated position in North Dakota in the second quarter of 2012. Heavy oil production for the six months ended June 30, 2013 increased by 4% to 40,012 bbl/d from 38,467 bbl/d for the same period in 2012 primarily due to the successful development in the Peace River area. Natural gas production decreased by 6% to 42.2 mmcf/d for the first six months of 2013, as compared to 44.8 mmcf/d for the same period in 2012, primarily due to natural declines as we focused our capital spending on our oil projects.

Commodity Prices

Crude Oil

For the six months ended June 30, 2013, the West Texas Intermediate ("WTI") oil prompt price averaged US$94.30/bbl and has remained fairly constant. The stability in pricing over this period was supported by generally constant supply and demand fundamentals. Late in the quarter, the WTI prompt price hit a high of $98.44/bbl. The strong price rally was driven by significant crude oil storage draws in the U.S., exceptionally strong refinery utilization rates and to a lesser extent unexpected global supply disruptions. For the three months ended June 30, 2013, the WTI oil prompt price averaged US$94.22/bbl.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 27% for the six months ended June 30, 2013 and 20% for the three months ended June 30, 2013, as compared to 22% and 24%, respectively, for the same periods in 2012. Factors driving a stronger WCS differential in the second quarter of 2013 were a steady demand for heavy oil, declines in Canadian crude storage levels, increased rail shipments of heavy oil and the return of refineries from maintenance.

Natural Gas

For the six months ended June 30, 2013, the AECO natural gas price averaged $3.08/mcf, as compared to $2.18/mcf in the same period of 2012. Demand for natural gas increased due to colder than normal weather in February 2013 for most of the continent resulting in larger than normal natural gas storage withdrawals, which caused natural gas prices to rally in line with stronger fundamentals. U.S. natural gas inventories normalized in April 2013 and moved below the five year average for the first time since 2011. During the shoulder and summer cooling seasons, prices have softened due to moderate weather conditions and continued U.S. production growth. For the three months ended June 30, 2013, the AECO natural gas price averaged $3.07/mcf, as compared to $1.84/mcf in the same period of 2012, and $3.08/mcf in the first quarter of 2013.

	Three Months Ended June 30			Six Months Ended June 30		
	2013	2012	Change	**2013**	2012	Change
Benchmark Averages						
WTI oil (US$/bbl)(1)	**$ 94.22**	$ 93.49	1%	**$ 94.30**	$ 98.20	(4%)
WCS heavy oil (US$/bbl)(2)	**$ 75.07**	$ 70.62	6%	**$ 68.75**	$ 76.06	(10%)
Heavy oil differential(3)	**(20%)**	(24%)		**(27%)**	(22%)	
CAD/USD average exchange rate	**1.0231**	1.0102	1%	**1.0159**	1.0052	1%
Edmonton par oil ($/bbl)	**$ 92.94**	$ 84.42	10%	**$ 90.77**	$ 88.55	3%
AECO natural gas price ($/mcf)(4)	**$ 3.07**	$ 1.84	67%	**$ 3.08**	$ 2.18	41%
Baytex Average Sales Prices						
Light oil and NGL ($/bbl)(6)	**$ 77.85**	$ 71.62	9%	**$ 77.30**	$ 76.97	–%
Heavy oil ($/bbl)(5)	**$ 63.92**	$ 56.31	14%	**$ 57.82**	$ 60.38	(4%)
Physical forward sales contracts gain ($/bbl)	**–**	1.11		**1.25**	1.27	
Heavy oil, net ($/bbl)	**$ 63.92**	$ 57.42	11%	**$ 59.07**	$ 61.65	(4%)
Total oil and NGL, net ($/bbl)	**$ 66.17**	$ 59.63	11%	**$ 62.12**	$ 64.10	(3%)
Natural gas ($/mcf)(6)	**$ 3.59**	$ 2.00	80%	**$ 3.53**	$ 2.23	58%
Summary						
Weighted average ($/boe)(6)	**$ 60.42**	$ 52.04	16%	**$ 55.99**	$ 55.94	–%
Physical forward sales contracts gain ($/boe)	**–**	0.93		**0.91**	1.06	
Weighted average, net ($/boe)	**$ 60.42**	$ 52.97	14%	**$ 56.90**	$ 57.00	–%

(1) *WTI refers to the arithmetic average based on NYMEX prompt month WTI.*
(2) *WCS refers to the average posting price for the benchmark WCS heavy oil.*
(3) *Heavy oil differential refers to the WCS discount to WTI.*
(4) *AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter.*
(5) *Baytex's realized heavy oil prices are calculated based on sales volumes, net of blending costs.*
(6) *Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The above pricing information in the table excludes the impact of financial derivatives.*

During the second quarter of 2013, Baytex's average sales price for light oil and NGL was $77.85/bbl, up 9% from $71.62/bbl in the second quarter of 2012. Baytex's realized heavy oil price during the second quarter of 2013, prior to physical forward sales contracts, was $63.92/bbl, or 83% of WCS. This compares to a realized heavy oil price in the second quarter of 2012, prior to physical forward sales contracts, of $56.31/bbl, or 79% of WCS. The discount to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Net of physical forward sales contracts, Baytex's realized heavy oil price during the second quarter of 2013 was $63.92/bbl, up from $57.42/bbl in the second quarter of 2012. Baytex's realized natural gas price for the three months ended June 30, 2013 was $3.59/mcf, up from $2.00/mcf in the second quarter of 2012. Baytex's realized natural gas price for the three months ended June 30, 2013 was greater than the benchmark price by $0.52/mcf as the Company benefited from the AECO spot market prices being significantly higher than the near-term contract price since March 2013.

During the first six months of 2013, Baytex's average sales price for light oil and NGL was $77.30/bbl, comparable to $76.97/bbl in the same period as 2012. Baytex's realized heavy oil price during the first six months of 2013, prior to physical forward sales contracts, was $57.82/bbl, or 83% of WCS. This compares to a realized heavy oil price in the first six months of 2012, prior to physical forward sales contracts, of $60.38/bbl, or 79% of WCS. The discount to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Net of physical forward sales contracts, Baytex's realized heavy oil price during the six months ended June 30, 2013 was $59.07/bbl, down from $61.65/bbl in the first six months of 2012 mainly due to pipeline apportionments, and wider quality discounts in the first quarter of 2013. Baytex's realized natural gas price for the six months ended June 30, 2013 was $3.53/mcf, up from $2.23/mcf in the same period in 2012.

Gross Revenues

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for %)	**2013**	2012	Change	**2013**	2012	Change
Oil revenue						
Light oil and NGL	**$ 58,106**	$ 46,206	26%	**$ 112,794**	$ 102,649	10%
Heavy oil	**248,458**	201,130	24%	**428,818**	431,635	(1%)
Total oil revenue	**306,564**	247,336	24%	**541,612**	534,284	1%
Natural gas revenue	**14,730**	8,086	82%	**26,962**	18,162	48%
Total oil and natural gas revenue	**321,294**	255,422	26%	**568,574**	552,446	3%
Heavy oil blending revenue	**19,717**	28,826	(32%)	**45,382**	75,157	(40%)
Total petroleum and natural gas revenues	**$ 341,011**	$ 284,248	20%	**$ 613,956**	$ 627,603	(2%)

Petroleum and natural gas revenues increased 20% to $341.0 million for the three months ended June 30, 2013 from $284.2 million for the same period in 2012. The growth in revenues for the three months ended June 30, 2013 was driven by a 24% increase in heavy oil revenues due to higher heavy oil volumes in the Peace River area and stronger WCS differentials, a 26% increase in light oil and NGL revenues due to success in our U.S. drilling program and higher realized light oil and NGL pricing and an 82% increase in natural gas revenues due to an 80% increase in realized natural gas pricing, as compared to the second quarter of 2012. Revenue for the three months ended June 30, 2013 was slightly offset by the decrease in heavy oil blending revenue, which was down 32% from the same period last year due to an increase in contracted volumes of heavy oil being transported by rail. Unlike transportation through oil pipelines, transportation of heavy oil by rail does not require condensate blending. The decrease in heavy oil blending revenue is offset by a decrease in heavy oil blending costs.

Petroleum and natural gas revenues decreased 2% to $614.0 million for the six months ended June 30, 2013 from $627.6 million for the same period in 2012. The reduction in revenues was driven by lower heavy oil blending revenue for the six months ended June 30, 2013, which was down 40% from the same period last year due to an increase in contracted volumes of heavy oil being transported by rail. These reductions to revenues were partially offset in the period by a 10% increase in light oil and NGL revenues due to success in our U.S. drilling program and a 48% increase in natural gas revenues due to significant increases to realized natural gas pricing, as compared to the same period in 2012.

Royalties

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2013**	2012	Change	**2013**	2012	Change
Royalties	**$ 62,010**	$ 46,020	35%	**$ 107,288**	$ 99,014	8%
Royalty rates:						
Light oil, NGL and natural gas	**18.3%**	18.3%		**21.7%**	18.4%	
Heavy oil	**19.6%**	17.9%		**18.0%**	17.8%	
Average royalty rates(1)	**19.3%**	18.0%		**18.9%**	17.9%	
Royalty expenses per boe	**$ 11.66**	$ 9.54	22%	**$ 10.74**	$ 10.22	5%

(1) *Average royalty rate excludes sales of heavy oil blending diluents and the effects of financial derivatives.*

Total royalties for the second quarter of 2013 increased to $62.0 million from $46.0 million in the second quarter of 2012. Total royalties for the second quarter of 2013 were 19.3% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 18.0% for the same period in 2012. Total royalties for the six months ended June 30, 2013 increased to $107.3 million from $99.0 million in the six months ended June 30, 2012. Total royalties for the first six months of 2013 were 18.9% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 17.9% for the same period in 2012.

Royalty rates in the three months ended June 30, 2013 and 2012 for light oil, NGL and natural gas were unchanged at 18.3%. Royalty rates for heavy oil increased from 17.9% in the three months ended June 30, 2012 to 19.6% in the three months ended June 30, 2013 due to higher realized pricing in the second quarter of 2013, and the resulting impact on price sensitive royalties.

Royalty rates for light oil, NGL and natural gas increased from 18.4% in the six months ended June 30, 2012 to 21.7% in the six months ended June 30, 2013 primarily due to higher royalties on U.S. properties resulting from a carry obligation and higher realized pricing in the first six months of 2013, partially offset by a higher number of wells qualifying under lower royalty rates and a gas cost allowance credit related to prior years. Royalty rates for heavy oil were essentially unchanged from 17.8% in the six months ended June 30, 2012, compared to 18.0% in the six months ended June 30, 2013. We expect royalty rates to average approximately 20-21% for full-year 2013 as a result of certain oil sands projects reaching payout and farm-in agreements.

Financial Derivatives

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	2013	2012	Change	2013	2012	Change
Realized gain (loss) on financial derivatives[1]						
Crude oil	$ 8,748	$ 7,688	$ 1,060	$ 15,609	$ (865)	$ 16,474
Natural gas	(264)	1,763	(2,027)	79	2,988	(2,909)
Foreign currency	147	917	(770)	813	2,798	(1,985)
Interest rate	137	112	25	(3,605)	(1,581)	(2,024)
Total	$ 8,768	$ 10,480	$ (1,712)	$ 12,896	$ 3,340	$ 9,556
Unrealized gain (loss) on financial derivatives[2]						
Crude oil	$ 5,226	$ 53,309	$ (48,083)	$ (5,074)	$ 44,391	$ (49,465)
Natural gas	3,037	(1,976)	5,013	650	(1,608)	2,258
Foreign currency	(8,539)	(2,893)	(5,646)	(11,476)	419	(11,895)
Interest rate	(175)	(1,056)	881	3,554	(20)	3,574
Total	$ (451)	$ 47,384	$ (47,835)	$ (12,346)	$ 43,182	$ (55,528)
Total gain (loss) on financial derivatives						
Crude oil	$ 13,974	$ 60,997	$ (47,023)	$ 10,535	$ 43,526	$ (32,991)
Natural gas	2,773	(213)	2,986	729	1,380	(651)
Foreign currency	(8,392)	(1,976)	(6,416)	(10,663)	3,217	(13,880)
Interest rate	(38)	(944)	906	(51)	(1,601)	1,550
Total	$ 8,317	$ 57,864	$ (49,547)	$ 550	$ 46,522	$ (45,972)

(1) Realized gain (loss) on financial derivatives represents actual cash settlement or receipts for the financial derivatives.
(2) Unrealized gain (loss) on financial derivatives represents the change in fair value of the financial derivatives during the period.

The realized gain of $8.8 million for the three months ended June 30, 2013 on derivative contracts relates to favorable contracts entered into when crude oil prices were high. The unrealized mark-to-market loss of $0.5 million for the three months ended June 30, 2013 relates to a weakening Canadian dollar against the U.S. dollar at June 30, 2013, as compared to March 31, 2013. This was partially offset by favourable crude oil contracts entered into during the quarter and lower forecasted natural gas prices at June 30, 2013 as compared to March 31, 2013.

The realized gain of $12.9 million for the six months ended June 30, 2013 on derivative contracts relates to favorable contracts entered when crude oil prices were high, partially offset by losses on interest rate swaps as London Interbank Offer Rates ("LIBOR") remained low. The unrealized mark-to-market loss of $12.3 million for the six months ended June 30, 2013 relates to a weakening Canadian dollar against the U.S. dollar at June 30, 2013, as compared to December 31, 2012, and the reversal of previously recorded unrealized gains on crude oil contracts as they settled upon maturity. This was partially offset by settlement of previously recorded unrealized losses on interest rate contracts.

A summary of the risk management contracts in place as at June 30, 2013 and the accounting treatment of the Company's financial instruments are disclosed in note 15 to the consolidated financial statements.

Production and Operating Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2013**	2012	Change	**2013**	2012	Change
Production and operating expenses	**$ 68,999**	$ 56,967	21%	**$ 134,215**	$ 115,254	16%
Production and operating expenses per boe:						
Heavy oil	**$ 12.74**	$ 10.62	20%	**$ 13.30**	$ 10.84	23%
Light oil, NGL and natural gas	**$ 13.61**	$ 14.99	(9%)	**$ 13.78**	$ 14.63	(6%)
Total	**$ 12.97**	$ 11.81	10%	**$ 13.43**	$ 11.89	13%

Production and operating expenses for the three months ended June 30, 2013 increased to $69.0 million from $57.0 million for the same period in 2012. This increase is primarily due to higher production volumes, along with wet and snowy spring conditions in Saskatchewan and North Dakota, and increases in the costs of fluid handling, labour, and energy and chemical inputs. This resulted in production and operating expenses of $12.97/boe for the three months ended June 30, 2013, as compared to $11.81/boe for the same period in 2012.

Production and operating expenses for the six months ended June 30, 2013 increased to $134.2 million from $115.3 million for the same period in 2012. This increase is primarily due to higher production volumes, along with harsh winter and wet and snowy spring conditions in Saskatchewan and North Dakota, and increases in the costs of fluid handling, labour, and energy and chemical inputs. This resulted in production and operating expenses of $13.43/boe for the six months ended June 30, 2013, as compared to $11.89/boe for the same period in 2012.

Transportation and Blending Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2013**	2012	Change	**2013**	2012	Change
Blending expenses	**$ 19,717**	$ 28,826	(32%)	**$ 45,382**	$ 75,157	(40%)
Transportation expenses	**21,723**	18,964	15%	**42,194**	34,370	23%
Total transportation and blending expenses	**$ 41,440**	$ 47,790	(13%)	**$ 87,576**	$ 109,527	(20%)
Transportation expenses per boe[1]:						
Heavy oil	**$ 5.32**	$ 5.18	3%	**$ 5.56**	$ 4.66	19%
Light oil, NGL and natural gas	**$ 0.74**	$ 0.61	21%	**$ 0.68**	$ 0.66	3%
Total	**$ 4.08**	$ 3.93	4%	**$ 4.22**	$ 3.55	19%

(1) Transportation expenses per boe are before the purchase of blending diluent.

Transportation and blending expenses for the second quarter of 2013 were $41.4 million, as compared to $47.8 million for the second quarter of 2012. Transportation and blending expenses for the first six months of 2013 were $87.6 million, as compared to $109.5 million for the same period in 2012.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications and to facilitate the marketing of its heavy oil. The cost of blending diluent is effectively recovered in the sale price of the blended product. In the second quarter of 2013, blending expenses were $19.7 million for the purchase of 2,128 bbl/d of condensate at $101.82/bbl, as compared to $28.8 million for the purchase of 3,114 bbl/d at $101.73/bbl for the same period last year. For the six months ended June 30, 2012, blending expenses were $45.4 million for the purchase of 2,403 bbl/d of condensate at $104.34/bbl, as compared to $75.2 million for the purchase of 3,867 bbl/d at $106.79/bbl for the same period last year. This decrease in blending for the three and six months ended June 30, 2013, as compared to the comparable periods of 2012, is due to higher contracted volumes of heavy oil transported by rail which does not require blending diluent.

Transportation expenses were $4.08/boe for the three months ended June 30, 2013, as compared to $3.93/boe for the same period of 2012. The increase in transportation expenses per barrel of heavy oil for the three months ended June 30, 2013 is primarily driven by increased use of long-haul trucking to deliver a larger percentage of our heavy oil production at Peace River to market. Transportation expenses were $4.22/boe for the six months ended June 30, 2013, as compared to $3.55/boe for the same period of 2012. The increase in transportation expenses per barrel of heavy oil for the six months ended June 30, 2013 is primarily driven by increased use of long-haul trucking to deliver a larger percentage of our heavy oil production at Peace River to market and harsh winter conditions which caused delays and re-routings.

Operating Netback

	Three Months Ended June 30			Six Months Ended June 30		
($ per boe except for % and volume)	**2013**	2012	Change	**2013**	2012	Change
Sales volume (boe/d)	**58,440**	52,985	10%	**55,212**	53,255	4%
Operating netback[(1)]:						
Sales price[(2)]	**$ 60.42**	$ 52.97	14%	**$ 56.90**	$ 57.00	–%
Less:						
Royalties	**11.66**	9.54	22%	**10.74**	10.22	5%
Production and operating expenses	**12.97**	11.81	10%	**13.43**	11.89	13%
Transportation expenses	**4.08**	3.93	4%	**4.22**	3.55	19%
Operating netback before financial derivatives	**$ 31.71**	$ 27.69	15%	**$ 28.51**	$ 31.34	(9%)
Financial derivatives gain[(3)]	**1.65**	2.17		**1.29**	0.34	
Operating netback after financial derivatives gain	**$ 33.36**	$ 29.86	12%	**$ 29.80**	$ 31.68	(6%)

(1) Operating netback table includes revenues and costs associated with sulphur production.
(2) Sales price is shown net of blending costs and gains (losses) on physical delivery contracts.
(3) Financial derivatives reflect realized gains (losses) only.

Evaluation and Exploration Expense

Evaluation and exploration expense for the three months ended June 30, 2013 decreased to $2.0 million from $4.5 million for the same period in 2012 due to a decrease in both the expiration of undeveloped land leases and the impairment of evaluation and exploration assets that will not be developed.

Evaluation and exploration expense for the six months ended June 30, 2013 decreased to $5.6 million from $6.9 million for the same period in 2012 due to a decrease in the expiration of undeveloped land leases partially offset by an increase in the impairment of evaluation and exploration assets that will not be developed.

Depletion and Depreciation

Depletion and depreciation for the three months ended June 30, 2013 increased to $86.5 million from $70.6 million for the same period in 2012. On a sales-unit basis, the provision for the current quarter was $16.29/boe, as compared to $14.64/boe for the same quarter in 2012. The increase is the result of both increased production and growing production in areas with high depletable cost bases.

Depletion and depreciation for the six months ended June 30, 2013 increased to $165.1 million from $142.9 million for the same period in 2012. On a sales-unit basis, the provision for the first half of 2013 was $16.52/boe, as compared to $14.74/boe for the same period in 2012. The increase is the result of both increased production and growing production in areas with high depletable cost bases.

General and Administrative Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2013**	2012	Change	**2013**	2012	Change
General and administrative expenses	**$ 10,540**	$ 11,137	(5%)	**$ 22,090**	$ 22,325	(1%)
General and administrative expenses per boe	**$ 1.98**	$ 2.31	(14%)	**$ 2.21**	$ 2.30	(4%)

General and administrative expenses for the three months ended June 30, 2013 decreased to $10.5 million from $11.1 million for the same period in 2012 due to higher capital overhead recoveries from Baytex's capital spending program, partially offset by higher salary, technical and professional service costs. On a per boe basis, general and administrative expenses decreased from $2.31 in the second quarter of 2012 to $1.98 in the second quarter of 2013 primarily due to increased production.

General and administrative expenses for the six months ended June 30, 2013 decreased to $22.1 million from $22.3 million for the same period in 2012 due to higher capital overhead recoveries from Baytex's capital spending program, partially offset by higher salary, technical and professional service costs. On a per boe basis, general and administrative expenses decreased from $2.30 in the first half of 2012 to $2.21 in the first half of 2013 primarily due to increased production.

Share-based Compensation Expense

On January 1, 2011, Baytex adopted a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards may be granted to directors, officers and employees of the Company and its subsidiaries. Concurrent with the adoption of the Share Award Incentive Plan, Baytex ceased making grants under the Common Share Rights Incentive Plan (the "Share Rights Plan").

Compensation expense related to the Share Award Incentive Plan decreased to $9.8 million for the three months ended June 30, 2013 from $11.6 million for the three months ended June 30, 2012 due a one-time charge in 2012, offset by additional grants and the continued vesting of awards outstanding. Compensation expense related to the Share Rights Plan decreased to $0.1 million for the three months ended June 30, 2013, as compared to $0.7 million for the three months ended June 30, 2012.

Compensation expense related to the Share Award Incentive Plan increased to $18.6 million for the six months ended June 30, 2013, as compared to $18.0 million for the six months ended June 30, 2012 related to additional grants and the continued vesting of awards outstanding. Compensation expense related to the Share Rights Plan decreased to $0.3 million for the six months ended June 30, 2013, as compared to $1.2 million for the six months ended June 30, 2012. Compensation expense attributable to the Share Rights Plan decreased as outstanding rights continue to be exercised while no new grants have been made under this plan since January 1, 2011.

Compensation expense associated with the Share Award Incentive Plan and the Share Rights Plan is recognized in income over the vesting period of the share awards or share rights with a corresponding increase in contributed surplus. The issuance of common shares upon the conversion of share awards or exercise of share rights is recorded as an increase in shareholders' capital with a corresponding reduction in contributed surplus.

Financing Costs

($ thousands except for %)	Three Months Ended June 30 2013	2012	Change	Six Months Ended June 30 2013	2012	Change
Bank loan and other	$ 2,865	$ 3,144	(9%)	$ 4,480	$ 5,684	(21%)
Long-term debt	7,732	6,168	25%	15,394	12,281	25%
Accretion on asset retirement obligations	1,690	1,652	2%	3,350	3,279	2%
Debt financing costs	2,117	830	155%	2,156	849	154%
Financing costs	$ 14,404	$ 11,794	22%	$ 25,380	$ 22,093	15%

Financing costs for the three months ended June 30, 2013 increased to $14.4 million, as compared to $11.8 million in the second quarter of 2012. Financing costs for the six months ended June 30, 2013 increased to $25.4 million, as compared to $22.1 million in the first six months of 2012. The increase for the three and six months ended June 30, 2013 was primarily attributable to interest on the $300 million principal amount of 6.625% Series C senior unsecured debentures issued on July 19, 2012, and higher credit facility amendment fees, partially offset by the elimination of interest on the $150 million principal amount of 9.15% Series A senior unsecured debentures that were redeemed on August 26, 2012, and lower bank borrowing.

Foreign Exchange

($ thousands except for % and exchange rates)	Three Months Ended June 30 2013	2012	Change	Six Months Ended June 30 2013	2012	Change
Unrealized foreign exchange loss	$ 4,919	$ 8,105	(39%)	$ 8,736	$ 2,112	314%
Realized foreign exchange gain	(1,565)	(1,225)	28%	(3,601)	(100)	3,501%
Foreign exchange loss	$ 3,354	$ 6,880	(51%)	$ 5,135	$ 2,012	155%
CAD/USD exchange rates:						
At beginning of period	1.0156	0.9991		0.9949	1.0170	
At end of period	1.0512	1.0191		1.0512	1.0191	

The unrealized loss for the three and six months ended June 30, 2013 and 2012 is mainly due to foreign exchange translation of the U.S. dollar denominated debt outstanding and the movement of the Canadian dollar against the U.S. dollar in the period. The U.S. dollar denominated debt is comprised of the US$150 million Series B senior unsecured debentures and the US$180 million portion of the bank loan; the latter being repaid in July 2012.

The unrealized loss of $4.9 million for the second quarter of 2013, as compared to an unrealized loss of $8.1 million for the second quarter of 2012, was mainly the result of the weakened Canadian dollar against the U.S. dollar at both June 30, 2013 (as compared to March 31, 2013) and at June 30, 2012 (as compared to March 31, 2012). The realized gains for the three months ended June 30, 2013 and 2012 were mainly due to day-to-day U.S. dollar denominated transactions as the U.S. dollar strengthened relative to the Canadian dollar.

The unrealized loss of $8.7 million for the first six months of 2013, as compared to an unrealized loss of $2.1 million for the first six months of 2012, was mainly the result of the weakened Canadian dollar against the U.S. dollar at both June 30, 2013 (as compared to December 31, 2012) and at June 30, 2012 (as compared to December 31, 2011). The realized gain in the six months ended June 30, 2013 was mainly due to day-to-day U.S. dollar denominated transactions as the U.S. dollar strengthened relative to the Canadian dollar.

Income Taxes

For the six months ended June 30, 2013, income tax expense was $17.8 million, as compared to $110.0 million for the six months ended June 30, 2012. When compared to the prior year, the decrease in income tax expense is primarily the result of a decrease in the amount of gain on divestiture of oil and gas properties and a decrease in unrealized gains on financial derivatives.

Net Income

Net income for the three months ended June 30, 2013 was $36.2 million, as compared to net income of $157.3 million for the same period in 2012. The decrease in net income was due to a gain on disposition of U.S. properties of $175.4 million in 2012 which was not repeated in 2013, lower financial instrument gains, higher depletion and depreciation, offset by lower deferred income tax expenses.

Net income for the six months ended June 30, 2013 was $46.3 million, as compared to $200.2 million for the same period in 2012. The decrease in net income was due to a gain on disposition of U.S. properties of $175.4 million in 2012 which was not repeated in 2013, lower financial instrument gains, lower operating netbacks, higher depletion and depreciation, offset by lower deferred income tax expenses.

Other Comprehensive Income

Revenues and expenses of foreign operations are translated to Canadian dollars using average foreign currency exchange rates for the period. Monetary assets and liabilities that form part of the net investment in the foreign operation are translated at the period-end foreign currency exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in shareholders' equity and are recognized in net income when there has been a disposal or partial disposal of the foreign operation.

The $1.1 million balance of accumulated other comprehensive loss at June 30, 2013 is the sum of a $12.4 million foreign currency translation loss incurred as at December 31, 2012 and an $11.3 million foreign currency translation gain related to the six months ended June 30, 2013.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Payout ratio is calculated as cash dividends (net of participation in the Dividend Reinvestment Plan ("DRIP")) divided by funds from operations. Baytex considers these to be key measures of performance as they demonstrate its ability to generate the cash flow necessary to fund dividends and capital investments.

The following table reconciles cash flow from operating activities (a GAAP measure) to funds from operations (a non-GAAP measure):

	Three Months Ended			Six Months Ended	
($ thousands except for %)	**June 30, 2013**	March 31, 2013	June 30, 2012	**June 30, 2013**	June 30, 2012
Cash flow from operating activities	**$ 160,306**	$ 95,174	$ 122,701	**$ 255,480**	$ 274,062
Change in non-cash working capital	**6,776**	12,782	11,594	**19,558**	9,713
Asset retirement expenditures	**1,273**	2,973	377	**4,246**	1,148
Financing costs	**(14,404)**	(10,976)	(11,794)	**(25,380)**	(22,093)
Accretion on asset retirement obligations	**1,690**	1,660	1,652	**3,350**	3,279
Accretion on debentures and long-term debt	**163**	159	162	**322**	319
Funds from operations	**$ 155,804**	$ 101,772	$ 124,692	**$ 257,576**	$ 266,428
Dividends declared	**$ 81,432**	$ 80,959	$ 78,908	**$ 162,391**	$ 157,273
Reinvested dividends	**21,106**	24,510	26,965	**45,616**	49,771
Cash dividends declared (net of DRIP)	**$ 60,326**	$ 56,449	$ 51,943	**$ 116,775**	$ 107,502
Payout ratio	**52%**	80%	63%	**63%**	59%
Payout ratio (net of DRIP)	**39%**	55%	42%	**45%**	40%

Baytex does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of petroleum and natural gas assets, certain levels of capital expenditures are required to minimize production declines. In the petroleum and natural gas industry, due to the nature of reserve reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, it is possible that Baytex would be required to reduce or eliminate its dividends in order to fund capital expenditures. There can be no certainty that Baytex will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $60.3 million for the second quarter of 2013 were funded by funds from operations of $155.8 million. Cash dividends declared, net of DRIP participation, of $116.8 million for the first six months of 2013 were funded by funds from operations of $257.6 million.

LIQUIDITY AND CAPITAL RESOURCES

We regularly review our liquidity sources as well as our exposure to counterparties and have concluded that our capital resources are sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations in the short, medium and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business. We periodically review the financial capacity of our counterparties and, in certain circumstances, we will seek enhanced credit protection from a counterparty.

($ thousands)	June 30, 2013	December 31, 2012
Bank loan	$ 225,434	$ 116,394
Long-term debt(1)	457,680	449,235
Working capital deficiency	87,418	34,197
Total monetary debt	$ 770,532	$ 599,826

(1) Principal amount of instruments.

At June 30, 2013 total monetary debt was $770.5 million, as compared to $599.8 million at December 31, 2012. Bank borrowings at June 30, 2013 were $225.4 million. Total credit facilities in place are $850.0 million.

Our wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established a $40.0 million extendible operating loan facility with a chartered bank and a $810.0 million extendible syndicated loan facility with a syndicate of chartered banks, each of which constitute a revolving credit facility that is extendible annually for a 1, 2, 3 or 4 year period (subject to a maximum four-year term at any time). On June 4, 2013, Baytex Energy reached an agreement with its lending syndicate to amend the credit facilities to (i) increase the amount available under the extendible syndicated loan facility to $810.0 million (from $660.0 million), (ii) extend the maximum term of the revolving period for both the operating and syndicated loan facilities to four years (from three years) and, (iii) extend the maturity date of both the operating and syndicated loan facilities to June 14, 2017 (from June 14, 2015). The credit facilities contain standard commercial covenants for facilities of this nature. Baytex Energy is in compliance with all such covenants. The credit facilities do not require any mandatory principal payments prior to maturity. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or LIBOR, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by us and certain of our material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with the covenants under the credit facilities, our ability to pay dividends to shareholders may be restricted. A copy of the amended and restated credit agreement (and related amendments) which establishes the credit facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on July 22, 2011, July 10, 2012, January 14, 2013 and August 9, 2013).

The weighted average interest rate on the bank loan for the six months ended June 30, 2013 was 5.31% (year ended December 31, 2012 – 3.69% and six months ended June 30, 2012 – 3.50%).

On July 19, 2012, we issued $300 million principal amount of Series C senior unsecured debentures bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. Net proceeds of this issue were used to repay a portion of the amount drawn in Canadian currency on Baytex Energy's credit facilities. These debentures are unsecured and are subordinate to Baytex Energy's credit facilities.

On August 26, 2012, we redeemed our 9.15% Series A senior unsecured debentures due August 26, 2016 ($150 million principal amount) at 104.575% of the principal amount. The payment of the redemption price was funded by drawing upon Baytex Energy's credit facilities.

Pursuant to various agreements with our lenders, we are restricted from paying dividends to shareholders where the dividend would or could have a material adverse effect on us or our subsidiaries' ability to fulfill our respective obligations under our senior unsecured debentures and Baytex Energy's credit facilities.

Baytex believes that funds from operations, together with the existing credit facilities, will be sufficient to finance current operations, dividends to the shareholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of dividend is also discretionary, and the Company has the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes.

Capital Expenditures

Capital expenditures are summarized as follows:

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	2013	2012	2013	2012
Land	$ 2,415	$ 4,195	$ 5,400	$ 6,787
Seismic	208	694	766	1,542
Drilling and completion	122,425	69,256	241,170	164,591
Equipment	52,786	28,831	96,992	65,886
Other	–	(81)	28	7
Total exploration and development	$ 177,834	$ 102,895	$ 344,356	$ 238,813
Acquisitions – Properties	54	10,173	54	12,509
Proceeds from divestitures	(1,850)	(313,834)	(44,232)	(317,402)
Total acquisitions and divestitures	(1,796)	(303,661)	(44,178)	(304,893)
Total oil and natural gas expenditures	176,038	(200,766)	300,178	(66,080)
Other plant and equipment, net	1,350	1,623	4,720	6,667
Total capital expenditures	$ 177,388	$ (199,143)	$ 304,898	$ (59,413)

During the three months ended June 30, 2013, Baytex drilled 25.8 net wells, as compared to 22.9 net wells in the three months ended June 30, 2012. During the six months ended June 30, 2013, Baytex drilled 135.6 net wells, as compared to 94.3 net wells in the six months ended June 30, 2012. Over the first half of 2013, capital investment activity progressed as planned in our key development areas. For the remainder of 2013, Baytex plans to drill approximately 14 more multi-lateral horizontal wells in Peace River and approximately 50 net heavy oil wells in Lloydminster. In addition, we continue to progress our thermal development with facility construction now underway at both our 15-well cyclic steam stimulation module at Cliffdale and our pilot steam-assisted gravity drainage project at Angling Lake.

Our 2013 exploration and development capital expenditures are estimated to be approximately $520 million.

Shareholders' Capital

Baytex is authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. Baytex establishes the rights and terms of preferred shares upon issuance. As at August 8, 2013 the Company had 124,091,738 common shares and no preferred shares issued and outstanding.

Contractual Obligations

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's funds from operations on an ongoing manner. A significant portion of these obligations will be funded with funds from operations. These obligations as of June 30, 2013, and the expected timing of funding of these obligations, are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 263,697**	$ 263,697	$ –	$ –	$ –
Dividends payable to shareholders	**27,190**	27,190	–	–	–
Bank loan[(1)]	**225,434**	–	–	225,434	–
Long-term debt[(2)]	**457,680**	–	–	–	457,680
Operating leases	**43,176**	6,258	12,806	12,445	11,667
Processing agreements	**28,158**	1,557	4,387	4,553	17,661
Transportation agreements	**70,184**	1,296	18,631	17,742	32,515
Total	**$1,115,519**	$ 299,998	$ 35,824	$ 260,174	$ 519,523

(1) The bank loan is a covenant-based revolving loan that is extendible annually for a one, two, three or four year period (subject to a maximum four-year term at any time). Unless extended, the revolving period will end on June 14, 2017, with all amounts to be re-paid on such date.

(2) Principal amount of instruments.

Baytex also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. Programs to abandon and reclaim them are undertaken regularly in accordance with applicable legislative requirements.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Baytex is exposed to a number of financial risks, including market risk, liquidity risk and credit risk. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is managed by Baytex through a series of derivative contracts intended to manage the volatility of its operating cash flow. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Company incurring a loss. Baytex manages credit risk by entering into sales contracts with creditworthy entities and reviewing its exposure to individual entities on a regular basis.

A summary of the risk management contracts in place as at June 30, 2013 and the accounting treatment of the Company's financial instruments are disclosed in note 15 to the consolidated financial statements.

QUARTERLY FINANCIAL INFORMATION

	2013		2012				2011	
($ thousands, except per common share amounts)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Gross revenues	**341,011**	272,945	292,095	299,786	284,248	343,355	367,813	313,787
Net income	**36,192**	10,149	31,620	26,773	157,280	42,958	57,780	51,839
Per common share – basic	**0.29**	0.08	0.26	0.22	1.32	0.36	0.49	0.45
Per common share – diluted	**0.29**	0.08	0.26	0.22	1.30	0.36	0.48	0.44

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document 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 document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to: crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our business strategies, plans and objectives; our ability to fund our capital expenditures and dividends on our common shares from funds from operations; our average royalty rate for full-year 2013; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; funding sources for our cash dividends and capital program; the number of wells to be drilled in the remainder of 2013; our exploration and development capital expenditures for 2013; the timing of funding our financial obligations; and the existence, operation and strategy of our risk management program. 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: 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: 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.*

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.

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(thousands of Canadian dollars) (unaudited)*	June 30, 2013	December 31, 2012
ASSETS		
Current assets		
Cash	$ 2,354	$ 1,837
Trade and other receivables	200,412	170,972
Crude oil inventory	703	1,363
Financial derivatives	13,167	20,167
	216,636	194,339
Non-current assets		
Exploration and evaluation assets (note 3)	227,147	240,015
Oil and gas properties (note 4)	2,193,522	2,037,576
Other plant and equipment	31,886	28,392
Goodwill	37,755	37,755
	$ 2,706,946	$ 2,538,077
LIABILITIES		
Current liabilities		
Trade and other payables	$ 263,697	$ 181,558
Dividends payable to shareholders	27,190	26,811
Financial derivatives	18,689	10,826
	309,576	219,195
Non-current liabilities		
Bank loan (note 5)	225,434	116,394
Long-term debt (note 6)	449,856	441,195
Asset retirement obligations (note 7)	242,306	265,520
Deferred income tax liability	209,418	189,160
Financial derivatives	5,079	7,201
	1,441,669	1,238,665
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 8)	1,932,025	1,860,358
Contributed surplus	64,520	65,615
Accumulated other comprehensive loss	(1,119)	(12,462)
Deficit	(730,149)	(614,099)
	1,265,277	1,299,412
	$ 2,706,946	$ 2,538,077

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	Three Months Ended June 30		Six Months Ended June 30	
(thousands of Canadian dollars, except per common share amounts) *(unaudited)*	2013	2012	2013	2012
Revenues, net of royalties (note 12)	$ 279,001	$ 238,228	$ 506,668	$ 528,589
Expenses				
Production and operating	68,999	56,967	134,215	115,254
Transportation and blending	41,440	47,790	87,576	109,527
Exploration and evaluation (note 3)	1,995	4,467	5,577	6,930
Depletion and depreciation	86,529	70,581	165,110	142,892
General and administrative	10,540	11,137	22,090	22,325
Share-based compensation (note 9)	9,894	12,345	18,938	19,201
Financing costs (note 13)	14,404	11,794	25,380	22,093
Gain on financial derivatives (note 15)	(8,317)	(57,864)	(550)	(46,522)
Foreign exchange loss (note 14)	3,354	6,880	5,135	2,012
Gain on divestiture of oil and gas properties	–	(175,406)	(20,951)	(175,406)
	228,838	(11,309)	442,520	218,306
Net income before income taxes	50,163	249,537	64,148	310,283
Income tax expense (note 11)				
Current income tax	–	16,664	–	16,664
Deferred income tax expense	13,971	75,593	17,807	93,381
	13,971	92,257	17,807	110,045
Net income attributable to shareholders	$ 36,192	$ 157,280	$ 46,341	$ 200,238
Other comprehensive income				
Foreign currency translation adjustment	7,457	6,954	11,343	1,568
Comprehensive income	$ 43,649	$ 164,234	$ 57,684	$ 201,806
Net income per common share (note 10)				
Basic	$ 0.29	$ 1.32	$ 0.37	$ 1.68
Diluted	$ 0.29	$ 1.30	$ 0.37	$ 1.66
Weighted average common shares (note 10)				
Basic	123,271	119,387	122,883	118,975
Diluted	124,362	120,991	124,138	120,839

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) *(unaudited)*	Shareholders' capital	Contributed surplus[1]	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at December 31, 2011	$ 1,680,184	$ 85,716	$ (3,546)	$ (555,620)	**$ 1,206,734**
Dividends to shareholders	–	–	–	(157,273)	**(157,273)**
Exercise of share rights	36,492	(21,428)	–	–	**15,064**
Vesting of share awards	14,086	(14,086)	–	–	**–**
Share-based compensation	–	19,201	–	–	**19,201**
Issued pursuant to dividend reinvestment plan	47,473	–	–	–	**47,473**
Comprehensive income for the period	–	–	1,568	200,238	**201,806**
Balance at June 30, 2012	$ 1,778,235	$ 69,403	$ (1,978)	$ (512,655)	**$ 1,333,005**
Balance at December 31, 2012	$ 1,860,358	$ 65,615	$ (12,462)	$ (614,099)	**$ 1,299,412**
Dividends to shareholders	–	–	–	(162,391)	**(162,391)**
Exercise of share rights	13,495	(8,194)	–	–	**5,301**
Vesting of share awards	11,839	(11,839)	–	–	**–**
Share-based compensation	–	18,938	–	–	**18,938**
Issued pursuant to dividend reinvestment plan	46,333	–	–	–	**46,333**
Comprehensive income for the period	–	–	11,343	46,341	**57,684**
Balance at June 30, 2013	$ 1,932,025	$ 64,520	$ (1,119)	$ (730,149)	**$ 1,265,277**

(1) Contributed surplus is comprised of share-based compensation.

See accompanying notes to the condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended June 30		Six Months Ended June 30	
(thousands of Canadian dollars) (unaudited)	**2013**	2012	**2013**	2012
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income for the period	**$ 36,192**	$ 157,280	**$ 46,341**	$ 200,238
Adjustments for:				
Share-based compensation (note 9)	**9,894**	12,345	**18,938**	19,201
Unrealized foreign exchange loss (note 14)	**4,919**	8,105	**8,736**	2,112
Exploration and evaluation	**1,995**	5,100	**5,577**	6,930
Depletion and depreciation	**86,529**	70,581	**165,110**	142,892
Unrealized loss (gain) on financial derivatives (note 15)	**451**	(47,384)	**12,346**	(43,182)
Gain on divestitures of oil and gas properties	**–**	(175,406)	**(20,951)**	(175,406)
Current income tax expense on divestiture	**–**	16,664	**–**	16,664
Deferred income tax expense	**13,971**	75,593	**17,807**	93,381
Financing costs (note 13)	**14,404**	11,794	**25,380**	22,093
Change in non-cash working capital	**(6,776)**	(11,594)	**(19,558)**	(9,713)
Asset retirement obligations settled (note 7)	**(1,273)**	(377)	**(4,246)**	(1,148)
	160,306	122,701	**255,480**	274,062
Financing activities				
Payment of dividends	**(58,436)**	(54,004)	**(115,680)**	(109,355)
Increase in bank loan	**69,592**	65,718	**109,040**	83,860
Issuance of common shares (note 8)	**1,583**	6,239	**5,301**	15,064
Interest paid	**(5,461)**	(3,676)	**(21,999)**	(18,228)
	7,278	14,277	**(23,338)**	(28,659)
Investing activities				
Additions to exploration and evaluation assets (note 3)	**(913)**	(3,963)	**(5,063)**	(7,694)
Additions to oil and gas properties (note 4)	**(176,921)**	(98,932)	**(339,293)**	(231,119)
Property acquisitions	**(54)**	(10,173)	**(54)**	(12,509)
Proceeds from divestiture of oil and gas properties	**1,850**	313,834	**44,232**	317,402
Current income tax expense in divestiture	**–**	(16,664)	**–**	(16,664)
Additions to other plant and equipment, net of disposals	**(1,350)**	(1,623)	**(4,720)**	(6,667)
Change in non-cash working capital	**13,104**	(9,276)	**74,935**	16,842
	(164,284)	173,203	**(229,963)**	59,591
Impact of foreign currency translation on cash balances	**(1,177)**	(527)	**(1,662)**	(375)
Change in cash	**2,123**	309,654	**517**	304,619
Cash, beginning of period	**231**	2,812	**1,837**	7,847
Cash, end of period	**$ 2,354**	$ 312,466	**$ 2,354**	$ 312,466

See accompanying notes to the condensed consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at June 30, 2013 and December 31, 2012 and for the three and six months ended June 30, 2013 and 2012
(all tabular amounts in thousands of Canadian dollars, except per common share amounts) (unaudited)

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 - 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PRESENTATION

The condensed interim unaudited consolidated financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards ("IAS") 34, Interim Financial Reporting, as issued by the International Accounting Standards Board. These consolidated financial statements do not include all the necessary annual disclosures as prescribed by International Financial Reporting Standards ("IFRS") and should be read in conjunction with the annual audited consolidated financial statements as of December 31, 2012. The Company's accounting policies are unchanged compared to December 31, 2012 except as listed in note 3 "Changes in Accounting Policies" of the consolidated financial statements of March 31, 2013. The use of estimates and judgments is also consistent with the December 31, 2012 financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on August 13, 2013.

The consolidated financial statements have been prepared on the historical cost basis, except for derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is rounded to the nearest thousand, except per share amounts and when otherwise indicated.

3. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2011	**$ 129,774**
Capital expenditures	13,406
Property acquisitions	135,772
Exploration and evaluation expense	(12,202)
Transfer to oil and gas properties	(3,902)
Divestitures	(22,074)
Foreign currency translation	(759)
As at December 31, 2012	**$ 240,015**
Capital expenditures	5,063
Exploration and evaluation expense	(5,577)
Transfer to oil and gas properties	(13,901)
Divestitures	(656)
Foreign currency translation	2,203
As at June 30, 2013	**$ 227,147**

4. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2011	**$ 2,471,419**
Capital expenditures	405,219
Property acquisitions	8,270
Transferred from exploration and evaluation assets	3,902
Change in asset retirement obligations	5,429
Divestitures	(133,447)
Foreign currency translation	(2,483)
As at December 31, 2012	**$ 2,758,309**
Capital expenditures	339,293
Property acquisitions	54
Transferred from exploration and evaluation assets	13,901
Change in asset retirement obligations	(22,419)
Divestitures	(32,816)
Foreign currency translation	12,755
As at June 30, 2013	**$ 3,069,077**

Accumulated depletion	
As at December 31, 2011	**$ 439,259**
Depletion for the period	294,623
Divestitures	(13,089)
Foreign currency translation	(60)
As at December 31, 2012	**$ 720,733**
Depletion for the period	163,826
Divestitures	(10,191)
Foreign currency translation	1,187
As at June 30, 2013	**$ 875,555**

Carrying value	
As at December 31, 2012	**$ 2,037,576**
As at June 30, 2013	**$ 2,193,522**

5. BANK LOAN

As at	June 30, 2013	December 31, 2012
Bank loan	$ 225,434	$ 116,394

The Company's wholly-owned subsidiary, Baytex Energy Ltd. ("Baytex Energy"), has established a $40.0 million extendible operating loan facility with a chartered bank and a $810.0 million extendible syndicated loan facility with a syndicate of chartered banks, each of which constitute a revolving credit facility that is extendible annually for a 1, 2, 3 or 4 year period (subject to a maximum four-year term at any time). On June 4, 2013, Baytex Energy reached agreement with its lending syndicate to amend the credit facilities to (i) increase the amount available under the extendible syndicated loan facility to $810.0 million (from $660.0 million), (ii) extend the maximum term of the revolving period for both the operating and syndicated loan facilities to four years (from three years) and, (iii) extend the maturity date of both the operating and syndicated loan facilities to June 14, 2017 (from June 14, 2015). The credit facilities contain standard commercial covenants for facilities of this nature and do not require any mandatory principal payments prior to maturity. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by Baytex and certain of its material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with the covenants under the credit facilities, Baytex's ability to pay dividends to its shareholders may be restricted.

Financing costs for six months ended June 30, 2013 include credit facility amendment fees of $2.1 million ($0.8 million for the six months ended June 30, 2012). The weighted average interest rate on the bank loan for the six months ended June 30, 2013 was 5.31% (3.50% for the six months ended June 30, 2012).

6. LONG-TERM DEBT

As at	June 30, 2013	December 31, 2012
6.75% Series B senior unsecured debentures (US$150,000 – principal) due February 17, 2021	$ 155,736	$ 147,305
6.625% Series C senior unsecured debentures (Cdn$300,000 – principal) due July 19, 2022	294,120	293,890
	$ 449,856	$ 441,195

Accretion expense on debentures of $0.2 million has been recorded in financing costs on long-term debt for the three months ended June 30, 2013 (three months ended June 30, 2012 – $0.2 million) and $0.3 million for the six months ended June 30, 2013 (six months ended June 30, 2012 – $0.3 million).

7. ASSET RETIREMENT OBLIGATIONS

	June 30, 2013	December 31, 2012
Balance, beginning of period	$ 265,520	$ 260,411
Liabilities incurred	9,049	7,092
Liabilities settled	(4,246)	(6,905)
Liabilities acquired	–	1,037
Liabilities divested	(1,294)	(2,372)
Accretion	3,350	6,631
Change in estimate[1]	(30,174)	(328)
Foreign currency translation	101	(46)
Balance, end of period	$ 242,306	$ 265,520

(1) Changes in the status of wells, discount rates and the estimated costs of abandonment and reclamation are factors resulting in a change in estimate.

8. SHAREHOLDERS' CAPITAL

Shareholders' Capital

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at June 30, 2013, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2011	**117,893**	**$ 1,680,184**
Issued on exercise of share rights	1,366	21,873
Transfer from contributed surplus on exercise of share rights	–	36,667
Transfer from contributed surplus on vesting and conversion of share awards	403	20,118
Issued pursuant to dividend reinvestment plan	2,206	101,516
Balance, December 31, 2012	**121,868**	**$ 1,860,358**
Issued on exercise of share rights	341	5,301
Transfer from contributed surplus on exercise of share rights	–	8,194
Transfer from contributed surplus on vesting and conversion of share awards	259	11,839
Issued pursuant to dividend reinvestment plan	1,125	46,333
Balance, June 30, 2013	**123,593**	**$ 1,932,025**

Monthly dividends of $0.22 per common share were declared by the Company during the three and six months ended June 30, 2013 for total dividends declared of $81.4 million ($60.3 million net of dividend reinvestment) and $162.4 million ($116.8 million net of dividend reinvestment), respectively.

Subsequent to June 30, 2013, the Company announced that a monthly dividend in respect of July 2013 operations of $0.22 per common share totaling $27.3 million ($20.5 million net of dividend reinvestment) will be paid on August 15, 2013 to shareholders of record on July 31, 2013.

9. EQUITY BASED PLANS

Share Award Incentive Plan

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "share awards") may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not at any time exceed 3.3% of the then-issued and outstanding common shares.

The Company recorded compensation expense related to the share awards of $9.8 million for the three months ended June 30, 2013 (three months ended June 30, 2012 – $11.6 million) and $18.6 million for the six months ended June 30, 2013 (six months ended June 30, 2012 – $18.0 million).

The fair value of share awards is determined at the date of grant using the closing price of the common shares and, for performance awards, an estimated payout multiplier. The amount of compensation expense is reduced by an estimated forfeiture rate, which has been estimated at 4.6%of outstanding share awards. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions. The estimated weighted average fair value for share awards at the measurement date is $43.37 per restricted award and performance award granted during the six months ended June 30, 2013 (six months ended June 30, 2012 – $56.04 per restricted award and performance award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000s)*	Number of performance awards *(000s)*	Number of share awards *(000s)*
Balance, December 31, 2011	**365**	**229**	**594**
Granted	370	306	676
Vested and converted to common shares	(133)	(130)	(263)
Forfeited	(36)	(17)	(53)
Balance, December 31, 2012	**566**	**388**	**954**
Granted	400	348	748
Vested and converted to common shares	(105)	(64)	(169)
Forfeited	(36)	(19)	(55)
Balance, June 30, 2013	**825**	**653**	**1,478**

Share Rights Plan

As a result of the conversion of the legal structure of the Company's predecessor, Baytex Energy Trust (the "Trust"), from an income trust to a corporation at year-end 2010, Baytex adopted a Common Share Rights Incentive Plan (the "Share Rights Plan") to facilitate the exchange of the outstanding unit rights (granted under the Unit Rights Plan of the Trust) for share rights.

As a result of the adoption of the Share Award Incentive Plan (as described above) effective January 1, 2011, no further grants will be made under the Share Rights Plan. The Share Rights Plan will remain in place until such time as all outstanding share rights have been exercised, canceled or expired.

Under the Share Rights Plan, share rights have a maximum term of five years and vest and become exercisable as to one-third on each of the first, second and third anniversaries of the grant date. Each share right entitles the holder thereof to acquire a common share upon payment of the exercise price, which may be reduced to account for future dividends (subject to certain performance criteria).

Baytex recorded compensation expense related to the share rights under the Share Rights Plan of $0.1 million for the three months ended June 30, 2013 (three months ended June 30, 2012 – $0.7 million) and $0.3 million for the six months ended June 30, 2013 (six months ended June 30, 2012 – $1.2 million).

The number of share rights outstanding and exercise prices are detailed below:

	Number of share rights *(000s)*	Weighted average exercise price
Balance, December 31, 2011[1]	**2,971**	**$ 16.98**
Exercised[2]	(1,366)	16.01
Forfeited[1]	(80)	21.27
Balance, December 31, 2012[1]	**1,525**	**$ 16.79**
Exercised[2]	(341)	15.77
Forfeited[1]	(4)	28.45
Balance, June 30, 2013[1]	**1,180**	**$ 16.07**

(1) Weighted average exercise price reflects the grant price less the reduction in exercise price for dividends and distributions.
(2) Weighted average exercise price includes rights exercised at both original grant prices and original grant prices reduced for dividends and distributions subsequent to grant date.

The following table summarizes information about the share rights outstanding at June 30, 2013:

	Exercise Prices Applying Original Grant Price					Exercise Prices Applying Original Grant Price Reduced for Dividends and Distributions Subsequent to Grant Date				
PRICE RANGE	Number Outstanding at June 30, 2013 *(000s)*	Weighted Average Grant Price	Weighted Average Remaining Term *(years)*	Number Exercisable at June 30, 2013 *(000s)*	Weighted Average Exercise Price	Number Outstanding at June 30, 2013 *(000s)*	Weighted Average Exercise Price	Weighted Average Remaining Term *(years)*	Number Exercisable at June 30, 2013 *(000s)*	Weighted Average Exercise Price
$2.92 to $10.50	–	$ –	–	–	$ –	327	$ 7.44	0.3	327	$ 7.44
$10.51 to $18.00	352	17.88	0.3	352	17.89	140	14.38	1.0	140	14.38
$18.01 to $25.50	124	22.44	1.1	124	22.44	645	19.36	1.4	643	19.36
$25.51 to $33.00	668	27.83	1.5	667	27.82	59	28.97	1.8	48	28.85
$33.01 to $40.50	33	35.79	2.2	21	35.55	8	34.57	2.0	7	34.37
$40.51 to $47.72	3	45.02	2.5	2	45.06	1	41.53	2.5	1	41.53
$2.92 to $47.72	1,180	$ 24.56	1.1	1,166	$ 24.42	1,180	$ 16.07	1.1	1,166	$ 15.90

10. NET INCOME PER SHARE

Baytex calculates basic income per share based on the net income attributable to shareholders and a weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted and share rights were exercised. The treasury stock method is used to determine the dilutive effect of share awards and share rights whereby the potential conversion of share awards, the estimated proceeds from the exercise of share rights and the amount of compensation expense, if any, attributed to future services not yet recognized are assumed to be used to purchase common shares at the average market price during the periods.

	Three Months Ended June 30, 2013			Three Months Ended June 30, 2012		
	Net income	Common Shares (000s)	Net income per share	Net income	Common Shares (000s)	Net income per share
Net income – basic	$ 36,192	123,271	$ 0.29	$ 157,280	119,387	$ 1.32
Dilutive effect of share awards	–	462	–	–	1,152	–
Dilutive effect of share rights	–	629	–	–	452	–
Net income – diluted	$ 36,192	124,362	$ 0.29	$ 157,280	120,991	$ 1.30

	Six Months Ended June 30, 2013			Six Months Ended June 30, 2012		
	Net income	Common Shares (000s)	Net income per share	Net income	Common Shares (000s)	Net income per share
Net income – basic	$ 46,341	122,883	$ 0.37	$ 200,238	118,975	$ 1.68
Dilutive effect of share awards	–	543	–	–	1,325	–
Dilutive effect of share rights	–	712	–	–	539	–
Net income – diluted	$ 46,341	124,138	$ 0.37	$ 200,238	120,839	$ 1.66

11. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2013	2012
Net income before income taxes	$ 64,148	$ 310,283
Expected income taxes at the statutory rate of 25.51% (2012 – 25.45%)(1)	16,364	78,967
Increase (decrease) in income taxes resulting from:		
Share-based compensation	4,830	4,886
Effect of rate adjustments for foreign jurisdictions	(3,595)	22,573
Other	208	3,619
Income tax expense	$ 17,807	$ 110,045

(1) The change in statutory rate is related to changes in the provincial apportionment of income.

12. REVENUES

	Three Months Ended June 30		Six Months Ended June 30	
	2013	2012	2013	2012
Petroleum and natural gas revenues	$ 340,070	$ 284,632	$ 611,859	$ 625,787
Royalty charges	(62,010)	(46,020)	(107,288)	(99,014)
Royalty income	941	(384)	2,097	1,816
Revenues, net of royalties	$ 279,001	$ 238,228	$ 506,668	$ 528,589

13. FINANCING COSTS

	Three Months Ended June 30		Six Months Ended June 30	
	2013	2012	2013	2012
Bank loan and other	$ 2,865	$ 3,144	$ 4,480	$ 5,684
Long-term debt	7,732	6,168	15,394	12,281
Accretion on asset retirement obligations	1,690	1,652	3,350	3,279
Debt financing costs	2,117	830	2,156	849
Financing costs	$ 14,404	$ 11,794	$ 25,380	$ 22,093

14. SUPPLEMENTAL INFORMATION

Foreign Exchange

	Three Months Ended June 30		Six Months Ended June 30	
	2013	2012	**2013**	2012
Unrealized foreign exchange loss	**$ 4,919**	$ 8,105	**$ 8,736**	$ 2,112
Realized foreign exchange gain	**(1,565)**	(1,225)	**(3,601)**	(100)
Foreign exchange loss	**$ 3,354**	$ 6,880	**$ 5,135**	$ 2,012

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Foreign Currency Risk

At June 30, 2013, the Company had in place the following currency derivative contracts:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	July to October 2013	US$1.00 million	1.0433	(1)
Monthly average collar	July to December 2013	US$1.00 million	1.0000 - 1.0725	(1)
Monthly average collar	July to December 2013	US$1.00 million	1.0100 - 1.0720	(1)
Monthly average collar	July to December 2013	US$1.00 million	1.0200 - 1.0575	(1)
Monthly average collar	July to December 2013	US$1.00 million	1.0200 - 1.0655	(1)
Monthly average collar	July to December 2013	US$1.00 million	1.0250 - 1.0702	(1)
Monthly average collar	July to December 2013	US$2.00 million	1.0300 - 1.0650	(1)
Monthly forward spot sale	July to December 2013	US$1.00 million	1.0320	(1)(3)
Monthly forward spot sale	July to December 2013	US$2.00 million	1.0336	(1)(3)
Monthly forward spot sale	July to December 2013	US$2.00 million	1.0346	(1)(3)
Monthly forward spot sale	July to December 2013	US$2.00 million	1.0450	(1)(3)
Monthly forward spot sale	July to December 2013	US$2.00 million	1.0500	(1)(3)
Monthly forward spot sale	July to December 2013	US$1.00 million	1.0530	(1)(3)
Monthly forward spot sale	July to December 2013	US$1.00 million	1.0547	(1)(3)
Monthly forward spot sale	July to December 2013	US$6.50 million	1.0236	(2)
Monthly forward spot sale	July to December 2013	US$1.00 million	1.0300	(1)(3)
Monthly average rate forward	July to December 2013	US$1.00 million	1.0274	(1)(3)
Monthly average rate forward	July to December 2013	US$3.75 million	1.0436	(1)
Monthly average collar	July to December 2013	US$0.25 million	0.9700 - 1.0310	(1)
Monthly average rate forward	July 2013 to December 2014	US$2.00 million	1.0394	(2)
Monthly average collar	January to December 2014	US$1.00 million	1.0300 - 1.0600	(1)
Monthly average collar	January to December 2014	US$1.00 million	1.0350 - 1.1100	(1)(4)
Monthly average collar	January to December 2014	US$0.50 million	1.0375 - 1.1100	(1)(4)
Monthly average collar	January to December 2014	US$0.50 million	1.0400 - 1.1100	(1)(4)
Monthly average collar	January to December 2014	US$1.00 million	1.0430 - 1.1100	(1)(4)
Monthly average collar	January to December 2014	US$1.00 million	1.0450 - 1.1100	(1)(4)
Monthly average collar	January to December 2014	US$1.00 million	1.0500 - 1.1100	(1)(4)
Sold call option	January to December 2014	US$0.50 million	1.0582	(1)(5)
Sold call option	January to December 2014	US$0.50 million	1.0620	(1)(5)
Sold call option	January to December 2014	US$0.50 million	1.0739	(1)(5)
Sold call option	January to December 2014	US$0.50 million	1.0724	(1)(5)
Sold call option	January to December 2014	US$0.50 million	1.0700	(1)(5)
Sold call option	January to December 2014	US$0.50 million	1.0725	(1)(5)
Sold call option	January to December 2014	US$0.50 million	1.0738	(1)(5)

(1) *Actual contract rate (CAD/USD).*
(2) *Based on the weighted average contract rates (CAD/USD).*
(3) *Counterparty has the option to extend the term by twelve months.*
(4) *Monthly sales price above the upper end of the price collar will result in settlement at the lower end of the price collar.*
(5) *Counterparty has the option to enter into a monthly average rate forward for the periods, amounts per month and sales prices noted.*

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	June 30, 2013	December 31, 2012	**June 30, 2013**	December 31, 2012
U.S. dollar denominated	**US$134,940**	US$124,048	**US$205,058**	US$201,980

Subsequent to June 30, 2013, Baytex added the following currency derivative contracts:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	July to December 2013	US$0.50 million	1.0775	(1)
Monthly average rate forward	July to December 2013	US$0.50 million	1.0750	(1)
Sold call option	January to December 2014	US$0.50 million	1.0775	(1)(2)
Sold call option	January to December 2014	US$0.50 million	1.0750	(1)(2)

(1) Actual contract rate (CAD/USD).

(2) Counterparty has the option to enter into a monthly average rate forward for the periods, amounts per month and sales price noted.

Interest Rate Risk

As at June 30, 2013, Baytex had the following interest rate swap financial derivative contracts:

Type	Period	Notional Principal Amount	Fixed interest rate	Floating rate index
Swap – pay fixed, receive floating	July 2013 to September 2014	US$90.0 million	4.06%	3-month LIBOR
Swap – pay fixed, receive floating	July 2013 to September 2014	US$90.0 million	4.39%	3-month LIBOR

Commodity Price Risk

Baytex monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of Baytex. Under the Company's risk management policy, financial derivatives are not to be used for speculative purposes.

Financial Derivative Contracts

At June 30, 2013, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	July to September 2013(2)	2,000 bbl/d	US$101.60	WTI
Fixed – Sell	July to December 2013	13,000 bbl/d	US$96.56	WTI
Fixed – Sell	July to December 2013(2)	1,000 bbl/d	US$99.50	WTI
Fixed – Sell	July to December 2013(2)	1,000 bbl/d	US$99.00	WTI
Fixed – Sell	July to December 2013(2)	1,000 bbl/d	US$104.70	WTI
Fixed – Sell	January to March 2014	2,000 bbl/d	US$99.44	WTI
Fixed – Sell	January to June 2014	250 bbl/d	US$100.70	WTI
Fixed – Sell	April to June 2014	1,000 bbl/d	US$99.53	WTI
Sold call option(3)	January to December 2014	2,000 bbl/d	US$95.00	WTI
Sold call option(3)	January to December 2014	1,500 bbl/d	US$96.00	WTI
Fixed – Buy	January to December 2014	380 bbl/d	US$101.06	WTI

(1) Based on the weighted average price/unit for the remainder of the contract.

(2) Counterparty has the option to extend the term by six months.

(3) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

Natural Gas	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	July to October 2013	2,500 mmBtu/d	US$4.16	NYMEX
Price collar	July to October 2013	10,000 mmBtu/d	US$3.50 – US$3.75	NYMEX
Fixed – Sell	July to December 2013	2,000 GJ/d	$3.37	AECO
Fixed – Sell	July to December 2013	5,000 mmBtu/d	US$4.05	NYMEX
Basis swap	July to December 2013	2,000 mmBtu/d	NYMEX less US$0.375	AECO
Basis swap	July to December 2013	1,000 mmBtu/d	NYMEX less US$0.388	AECO
Basis swap	July to December 2013	2,000 mmBtu/d	NYMEX less US$0.428	AECO
Price collar	November 2013 to March 2014	10,000 mmBtu/d	US$4.00 – US$4.50	NYMEX
Price collar	November 2013 to March 2014	2,500 mmBtu/d	US$4.20 – US$4.60	NYMEX
Fixed – Sell	January to December 2014	2,000 mmBtu/d	US$4.45	NYMEX

(1) Based on the weighted average price/unit for the remainder of the contract.

Financial derivatives are marked-to-market at the end of each reporting period, with the following reflected in the condensed consolidated statements of income and comprehensive income:

	Three Months Ended June 30		Six Months Ended June 30	
	2013	2012	**2013**	2012
Realized gain on financial derivatives	**$ (8,768)**	$ (10,480)	**$ (12,896)**	$ (3,340)
Unrealized loss (gain) on financial derivatives	**451**	(47,384)	**12,346**	(43,182)
Gain on financial derivatives	**$ (8,317)**	$ (57,864)	**$ (550)**	$ (46,522)

Subsequent to June 30, 2013, Baytex added the following financial derivative contracts:

Oil	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	July 2013	4,000 bbl/d	US$107.75	WTI
Fixed – Sell	July to September 2013	6,500 bbl/d	US$101.90	WTI
Fixed – Sell	July to November 2013	1,000 bbl/d	US$100.00	WTI
Fixed – Sell	August 2013	4,000 bbl/d	US$107.10	WTI
Sold call option[2]	August 2013	2,000 bbl/d	US$105.25	WTI
Fixed – Sell	September 2013	2,500 bbl/d	US$105.45	WTI
Sold call option[2]	September 2013	2,500 bbl/d	US$104.00	WTI
Fixed – Sell	October to December 2013	7,000 bbl/d	US$101.94	WTI
Sold call option[2]	October to December 2013	2,500 bbl/d	US$102.20	WTI
Fixed – Sell	October 2013 to March 2014	1,000 bbl/d	US$100.50	WTI
Fixed – Sell	December 2013 to March 2014	1,000 bbl/d	US$98.50	WTI
Sold call option[2]	December 2013 to March 2014	1,000 bbl/d	US$98.00	WTI
Fixed – Sell	January to March 2014	500 bbl/d	US$99.00	WTI
Fixed – Sell	January to June 2014	500 bbl/d	US$99.75	WTI
Fixed – Sell	January to December 2014	500 bbl/d	US$99.25	WTI
Sold call option[2]	January to December 2014	1,000 bbl/d	US$97.00	WTI
Fixed – Sell	April to June 2014	2,000 bbl/d	US$100.50	WTI
Sold call option[2]	April 2014 to March 2015	2,000 bbl/d	US$94.00	WTI
Fixed – Sell	July to December 2014	1,500 bbl/d	US$95.28	WTI
Sold call option[2]	July to December 2014	1,000 bbl/d	US$95.00	WTI
Sold call option[2]	July 2014 to June 2015	500 bbl/d	US$95.00	WTI

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Counterparty has the option to enter into a fixed sell for the periods, volumes and prices noted.

Physical Delivery Contracts

As at June 30, 2013, the following physical delivery contracts were held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts are not considered financial instruments; therefore, no asset or liability has been recognized in the consolidated financial statements.

Heavy Oil	Period	Volume	Weighted Average Price/Unit(1)
WCS Blend	July 2013 to December 2014	2,000 bbl/d	WTI × 81.00%
WCS Blend	July to December 2013	2,000 bbl/d	WTI less US$21.50
WCS Blend	July to December 2013	2,750 bbl/d	WTI × 80.00%
WCS Blend	July to December 2013	2,750 bbl/d	WTI less US$21.00

(1) Based on the weighted average price/unit for the remainder of the contract.

Condensate (diluent)	Period	Volume	Price/Unit
Fixed – Buy	July to December 2013	160 bbl/d	WTI plus US$3.10

At June 30, 2013, Baytex had committed to deliver the volumes of raw bitumen noted below to market on rail:

Heavy Oil	Period	Term Volume
Raw bitumen	July to September 2013	11,700 bbl/d
Raw bitumen	October to December 2013	11,700 bbl/d
Raw bitumen	January to March 2014	4,000 bbl/d
Raw bitumen	April to June 2014	3,675 bbl/d

16. CONSOLIDATING FINANCIAL INFORMATION – BASE SHELF PROSPECTUS

On August 4, 2011, Baytex filed a Short Form Base Shelf Prospectus with the securities regulatory authorities in each of the provinces of Canada (other than Québec) and a Registration Statement with the United States Securities and Exchange Commission (collectively, the "Shelf Prospectus"). The Shelf Prospectus allows Baytex to offer and issue common shares, subscription receipts, warrants, options and debt securities by way of one or more prospectus supplements at any time during the 25-month period that the Shelf Prospectus remains in place. The securities may be issued from time to time, at the discretion of Baytex, with an aggregate offering amount not to exceed $500 million (Canadian).

On July 19, 2012, Baytex issued $300 million of 6.625% Series C senior unsecured debentures due July 19, 2022 at par. The offering was made by way of a prospectus supplement dated July 10, 2012 to the Shelf Prospectus.

Any debt securities issued by Baytex pursuant to the Shelf Prospectus will be guaranteed by all of its direct and indirect wholly-owned material subsidiaries (the "Guarantor Subsidiaries"). The guarantees of the Guarantor Subsidiaries are full and unconditional and joint and several. These guarantees may in turn be guaranteed by Baytex. Other than investments in its subsidiaries, Baytex has no independent assets or operations.

Pursuant to the credit agreement governing Baytex Energy's credit facilities, Baytex Energy and its subsidiaries are prohibited from paying dividends to their shareholders that would have, or would reasonably be expected to have, a material adverse effect or would adversely affect or impair the ability or capacity of Baytex Energy to pay or fulfill any of its obligations under the credit agreement. In addition, Baytex Energy may not permit any of its subsidiaries to pay any dividends during the continuance of a default or event of default under the credit agreement.

The following tables present condensed interim unaudited consolidating financial information as at June 30, 2013, and December 31, 2012 and for the three and six months ended June 30, 2013 and 2012 for: 1) Baytex, on a stand-alone basis, 2) Guarantor subsidiaries, on a stand-alone basis, 3) non-guarantor subsidiaries, on a stand-alone basis and 4) Baytex, on a consolidated basis.

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
As at June 30, 2013					
Current assets	$ 7	$ 216,411	$ 218	$ –	$ 216,636
Intercompany advances and investments	1,665,897	(524,495)	86,539	(1,227,941)	–
Non-current assets	2,432	2,487,878	–	–	2,490,310
Current liabilities	40,060	269,261	255	–	309,576
Bank loan and long-term debt	449,856	225,434	–	–	675,290
Asset retirement obligation and other non-current liabilities	$ –	$ 456,803	$ –	$ –	$ 456,803
As at December 31, 2012					
Current assets	$ 4	$ 194,086	$ 249	$ –	$ 194,339
Intercompany advances and investments	1,756,923	(555,059)	70,298	(1,272,162)	–
Non-current assets	2,435	2,341,303	–	–	2,343,738
Current liabilities	39,478	179,503	214	–	219,195
Bank loan and long-term debt	441,195	116,394	–	–	557,589
Asset retirement obligation and other non-current liabilities	$ –	$ 461,881	$ –	$ –	$ 461,881
For the six months ended June 30, 2013					
Revenues, net of royalties	$ 14,302	$ 506,638	$ 12,639	$ (26,911)	$ 506,668
Production, operation and exploration	–	139,792	–	–	139,792
Transportation and blending	–	87,576	–	–	87,576
General, administrative and unit-based compensation	(30)	40,955	73	30	41,028
Financing, derivatives, foreign exchange and other (gains)/losses	23,874	12,082	(1)	(26,941)	9,014
Depletion and depreciation	–	165,110	–	–	165,110
Income tax expense	–	17,807	–	–	17,807
Net income (loss)	$ (9,542)	$ 43,316	$ 12,567	$ –	$ 46,341
For the three months ended June 30, 2013					
Revenues, net of royalties	$ 8,550	$ 278,626	$ 6,406	$ (14,581)	$ 279,001
Production, operation and exploration	–	70,994	–	–	70,994
Transportation and blending	–	41,440	–	–	41,440
General, administrative and unit-based compensation	(375)	20,383	51	375	20,434
Financing, derivatives, foreign exchange and other (gains)/losses	13,108	11,285	4	(14,956)	9,441
Depletion and depreciation	–	86,529	–	–	86,529
Income tax expense	–	13,971	–	–	13,971
Net income (loss)	$ (4,183)	$ 34,024	$ 6,351	$ –	$ 36,192

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
For the six months ended June 30, 2012					
Revenues, net of royalties	$ 11,708	$ 529,215	$ 8,324	$ (20,658)	$ 528,589
Production, operation and exploration	–	122,184	–	–	122,184
Transportation and blending	–	109,527	–	–	109,527
General, administrative and share-based compensation	626	41,400	126	(626)	41,526
Financing, derivatives, foreign exchange and other (gains)/losses	12,533	(190,327)	3	(20,032)	(197,823)
Depletion and depreciation	–	142,892	–	–	142,892
Income tax expense	–	110,045	–	–	110,045
Net income (loss)	$ (1,451)	$ 193,494	$ 8,195	$ –	$ 200,238
For the three months ended June 30, 2012					
Revenues, net of royalties	$ 5,875	$ 238,479	$ 4,418	$ (10,544)	$ 238,228
Production, operation and exploration	–	61,434	–	–	61,434
Transportation and blending	–	47,790	–	–	47,790
General, administrative and share-based compensation	251	23,454	28	(251)	23,482
Financing, derivatives, foreign exchange and other (gains)/losses	9,155	(213,458)	–	(10,293)	(214,596)
Depletion and depreciation	–	70,581	–	–	70,581
Income tax expense	–	92,257	–	–	92,257
Net income (loss)	$ (3,531)	$ 156,421	$ 4,390	$ –	$ 157,280
For the six months ended June 30, 2013					
Cash provided by (used in):					
Operating activities	$ 14,464	$ 241,265	$ (249)	$ –	$ 255,480
Payment of dividends	(115,680)	–	–	–	(115,680)
Decrease in bank loan	–	109,040	–	–	109,040
Change in intercompany loans	111,059	(111,059)	–	–	–
Increase in equity	5,301	–	–	–	5,301
Interest paid	(15,144)	(6,855)	–	–	(21,999)
Financing activities	(14,464)	(8,874)	–	–	(23,338)
Additions to exploration and evaluation assets	–	(5,063)	–	–	(5,063)
Additions to oil and gas properties	–	(339,293)	–	–	(339,293)
Property acquisition	–	(54)	–	–	(54)
Proceeds from divestitures	–	44,232	–	–	44,232
Additions to other plant and equipment, net of disposals	–	(4,720)	–	–	(4,720)
Change in non-cash working capital	–	74,935	–	–	74,935
Investing activities	–	(229,963)	–	–	(229,963)
Impact of foreign currency translation on cash balances	$ –	$ (1,662)	$ –	$ –	$ (1,662)

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
For the six months ended June 30, 2012					
Cash provided by (used in):					
Operating activities	$ 11,396	$ 251,897	$ 10,769	$ –	$ 274,062
Payment of dividends	(109,355)	–	–	–	(109,355)
Increase in bank loan	–	83,860	–	–	83,860
Increase (decrease) in intercompany loans	94,753	(21,108)	(73,645)	–	–
Increase in investments	–	(73,645)	–	73,645	–
Increase in equity	15,064	–	73,645	(73,645)	15,064
Interest paid	(11,858)	4,399	(10,769)	–	(18,228)
Financing activities	(11,396)	(6,494)	(10,769)	–	(28,659)
Additions to exploration and evaluation assets	–	(7,694)	–	–	(7,694)
Additions to oil and gas properties	–	(231,119)	–	–	(231,119)
Property acquisitions	–	(12,509)	–	–	(12,509)
Proceeds from divestitures	–	317,402	–	–	317,402
Current income tax expense on divestiture		(16,664)			(16,664)
Additions to other plant and equipment, net of disposals	–	(6,667)	–	–	(6,667)
Change in non-cash working capital	–	16,842	–	–	16,842
Investing activities	–	59,591	–	–	59,591
Impact of foreign currency translation on cash balances	$ –	$ (375)	$ –	$ –	$ (375)

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DRIP	Dividend Reinvestment Plan
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *Oil equivalent amounts may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Baytex Energy Corp.

James L. Bowzer
President and Chief Executive Officer
Baytex Energy Corp.

John A. Brussa(2)(3)(4)
Vice Chairman
Burnet, Duckworth & Palmer LLP

Edward Chwyl(2)(3)(4)
Lead Independent Director
Independent Businessman

Naveen Dargan(1)(2)(4)
Independent Businessman

R. E. T. (Rusty) Goepel(1)
Senior Vice President
Raymond James Ltd.

Gregory K. Melchin(1)
Independent Businessman

Mary Ellen Peters
Independent Businesswoman

Dale O. Shwed(3)
President and Chief Executive Officer
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Nominating and Governance Committee

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Bank of Montreal
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Barclays Bank PLC
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
Credit Suisse AG
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank
Wells Fargo Bank

OFFICERS

Raymond T. Chan
Executive Chairman

James L. Bowzer
President and Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Marty L. Proctor
Chief Operating Officer

Daniel G. Anderson
Vice President, U.S. Business Unit

Kendall D. Arthur
Vice President,
Saskatchewan Business Unit

Geoffrey J. Darcy
Vice President, Marketing

Murray J. Desrosiers
Vice President, General Counsel
and Corporate Secretary

Brian G. Ector
Vice President, Investor Relations

Cameron A. Hercus
Vice President, Corporate Development

Timothy R. Morris
Vice President, U.S. Business Development

Richard P. Ramsay
Vice President, Alberta/B.C. Business Unit

Gregory A. Sawchenko
Vice President, Land

AUDITORS

Deloitte LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE