SUMMARY

- Generated production of 84,812 boe/d (82% oil and NGL) in Q2/2015;
- Delivered funds from operations ("FFO") of $158.0 million ($0.77 per share) in Q2/2015;
- Realized an operating netback (sales price less royalties, production and operating expenses, and transportation expenses) in Q2/2015 of $20.66/boe ($25.85/boe including financial derivative gains);
- Advanced the multi-zone development potential of our Eagle Ford acreage with 30-day initial production rates per well ranging from 900 to 1,600 boe/d for two projects that targeted three separate horizons;
- Maintained a conservative payout ratio, net of participation in our dividend reinvestment plan ("DRIP"), of 24% (39% before DRIP) in Q2/2015; and
- Completed an equity financing on April 2, 2015, raising net proceeds of approximately $606 million which were applied to reduce outstanding indebtedness.

	Three Months Ended			Six Months Ended	
	June 30, 2015	March 31, 2015	June 30, 2014	June 30, 2015	June 30, 2014
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	$ 345,432	$ 285,615	$ 476,404	$ 631,047	$ 862,213
Funds from operations[1]	158,049	160,221	165,503	318,270	336,312
Per share – basic	0.77	0.95	1.22	1.70	2.57
Per share – diluted	0.77	0.95	1.21	1.70	2.54
Cash dividends declared[2]	37,908	41,466	75,397	79,375	138,838
Dividends declared per share	0.30	0.30	0.68	0.60	1.34
Net income (loss)	(26,955)	(175,916)	36,799	(202,871)	84,640
Per share – basic	(0.13)	(1.04)	0.27	(1.08)	0.65
Per share – diluted	(0.13)	(1.04)	0.27	(1.08)	0.64
Exploration and development	106,010	147,429	148,916	253,439	321,341
Acquisitions, net of divestitures	1,170	1,550	2,920,845	2,720	2,921,518
Total oil and natural gas capital expenditures	$ 107,180	$ 148,979	$ 3,069,761	$ 256,159	$ 3,242,859
Bank loan[3]	$ 192,255	$ 780,447	$ 952,402	$ 192,255	$ 952,402
Long-term debt[3]	1,493,013	1,513,002	1,329,487	1,493,013	1,329,487
Working capital deficiency	137,243	162,546	178,517	137,243	178,517
Total monetary debt[4]	$ 1,822,511	$ 2,455,995	$ 2,460,406	$ 1,822,511	$ 2,460,406

	Three Months Ended			Six Months Ended	
	June 30, 2015	March 31, 2015	June 30, 2014	**June 30, 2015**	June 30, 2014
OPERATING					
Daily production					
Heavy oil (bbl/d)	**35,439**	39,261	45,986	**37,339**	45,611
Light oil and condensate (bbl/d)	**25,899**	28,056	9,865	**26,971**	7,680
NGL (bbl/d)	**8,232**	8,224	2,475	**8,228**	2,232
Total oil and NGL (bbl/d)	**69,570**	75,541	58,326	**72,538**	55,523
Natural gas (mcf/d)	**91,456**	91,010	51,645	**91,234**	46,295
Oil equivalent (boe/d @ 6:1)(5)	**84,812**	90,710	66,934	**87,744**	63,239
Benchmark prices					
WTI oil (US$/bbl)	**57.94**	48.64	102.99	**53.29**	100.84
WCS heavy oil (US$/bbl)	**46.35**	33.91	82.95	**40.14**	79.25
Edmonton par oil ($/bbl)	**67.72**	51.94	106.68	**59.84**	103.43
LLS oil (US$/bbl)	**62.38**	50.55	106.81	**56.47**	105.86
Baytex average prices (before hedging)					
Heavy oil ($/bbl)(6)	**44.59**	28.57	79.26	**36.21**	75.26
Light oil and condensate ($/bbl)	**65.11**	52.34	104.16	**58.50**	101.20
NGL ($/bbl)	**15.78**	19.35	38.74	**17.55**	46.34
Total oil and NGL ($/bbl)	**48.82**	36.40	81.74	**42.39**	77.68
Natural gas ($/mcf)	**3.06**	3.22	4.84	**3.14**	5.01
Oil equivalent ($/boe)	**43.34**	33.54	75.06	**38.30**	71.92
CAD/USD noon rate at period end	**1.2474**	1.2683	1.0676	**1.2474**	1.0676
CAD/USD average rate for period	**1.2294**	1.2308	1.0894	**1.2353**	1.0964
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**24.14**	24.87	49.88	**24.87**	49.88
Low	**19.24**	16.03	44.30	**16.03**	38.90
Close	**19.43**	20.03	45.89	**20.03**	45.89
Volume traded (thousands)	**80,572**	122,179	45,952	**202,752**	99,733
NYSE					
Share price (US$)					
High	**20.10**	19.99	46.30	**19.99**	46.30
Low	**15.42**	13.14	40.70	**13.14**	35.34
Close	**15.58**	15.80	42.16	**15.8**	42.16
Volume traded (thousands)	**44,497**	24,213	3,552	**68,710**	7,702
Common shares outstanding (thousands)	**206,193**	169,001	165,421	**206,193**	165,421

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. We define funds from operations as cash flow from operating activities adjusted for finance costs, changes in non-cash operating working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends and capital investments. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and six months ended June 30, 2015.*

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

(3) *Principal amount of instruments.*

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

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

(6) *Heavy oil prices exclude condensate blending.*

Advisory Regarding Forward-Looking Statements

This report contains forward-looking statements relating to: our business strategies, plans and objectives; our annual average production rate for 2015; our capital budget for 2015; our plan for developing our properties in 2015, including the number and type of wells and the geographic location of wells; our Eagle Ford shale play, including initial production rates from new wells, our plans to use "stack and frac" pilots to target three zones in the Eagle Ford formation in addition to the overlying Austin Chalk formation and our assessment of the results of our "stack and frac" pilots; the timing of completion of the second phase of Genalta's Peace River Power Centre, the additional volumes of natural gas to be conserved and the amount of electricity to be generated; the outlook for the price differential between Western Canadian Select heavy oil and West Texas Intermediate light oil; our expectation regarding the payment of cash income taxes in 2015, including our effective tax rate; 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 on railways; the volume of heavy oil to be transported to market on railways in the third quarter of 2015; our liquidity and financial capacity; and the sufficiency of our financial resources to fund our operations. 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.

Oil and Gas Information

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. 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.

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

Non-GAAP Financial Measures

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

Total monetary debt is not a measurement based on GAAP in Canada. 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)) and the principal amount of both the long-term debt and the bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

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

Payout ratio is defined 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.

MESSAGE TO SHAREHOLDERS

Operations Review

During the second quarter, we continued to execute our 2015 capital program as planned and our results are consistent with expectations. In response to the weakness in commodity prices, our overall level of capital spending was lower for the third consecutive quarter as we deferred activity in Canada and reduced activity in the Eagle Ford. Reflective of this reduced activity, production averaged 84,812 boe/d (82% oil and NGL) in Q2/2015 as compared to 90,710 boe/d in Q1/2015. Capital expenditures for exploration and development activities totaled $106.0 million in Q2/2015, down from $147.4 million in Q1/2015, and $214.7 million in Q4/2014. In Q2/2015, we participated in the drilling of 51 (15.2 net) wells with a 100% success rate.

One of our key attributes is our portfolio of projects with strong capital efficiencies and high rates of return. Through negotiated cost savings with service providers, our portfolio of development opportunities in the Eagle Ford, Peace River and Lloydminster continue to provide attractive returns in today's low crude oil price environment.

Our 2015 production guidance remains at 84,000 to 88,000 boe/d with budgeted exploration and development expenditures of $500 to $575 million. Our 2015 capital program remains flexible and allows for adjustments to second half spending based on changes in the commodity price environment.

Wells Drilled – Three Months Ended June 30, 2015

	Crude Oil		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil										
Lloydminster	2	2.0	–	–	–	–	–	–	2	2.0
Peace River	–	–	–	–	–	–	–	–	–	–
	2	**2.0**	**–**	**–**	**–**	**–**	**–**	**–**	**2**	**2.0**
Light oil and natural gas										
Eagle Ford	12	3.4	37	9.8	–	–	–	–	49	13.2
Western Canada	–	–	–	–	–	–	–	–	–	–
	12	**3.4**	**37**	**9.8**	**–**	**–**	**–**	**–**	**49**	**13.2**
Total	**14**	**5.4**	**37**	**9.8**	**–**	**–**	**–**	**–**	**51**	**15.2**

Wells Drilled – Six Months Ended June 30, 2015

	Crude Oil		Natural Gas		Stratigraphic and Service		Dry and Abandoned		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Heavy oil										
Lloydminster	9	5.1	–	–	–	–	–	–	9	5.1
Peace River	1	1.0	–	–	5	5.0	–	–	6	6.0
	10	**6.1**	**–**	**–**	**5**	**5.0**	**–**	**–**	**15**	**11.1**
Light oil and natural gas										
Eagle Ford	48	10.8	67	17.6	–	–	2	0.6	117	29.1
Western Canada	–	–	–	–	–	–	–	–	–	–
	48	**10.8**	**67**	**17.6**	**–**	**–**	**2**	**0.6**	**117**	**29.1**
Total	**58**	**16.9**	**67**	**17.6**	**5**	**5.0**	**2**	**0.6**	**132**	**40.2**

U.S. Operations

Production in the Eagle Ford averaged 39,548 boe/d (79% oil and NGL) during Q2/2015, as compared to 41,076 boe/d in Q1/2015 and 38,035 boe/d in Q4/2014. Capital expenditures in the Eagle Ford in Q2/2015 totaled $98.3 million, down from $126.2 million in Q1/2015 and $149.5 million in Q4/2014. This reduction is reflective of reduced activity levels combined with negotiated cost savings with service providers.

We continued to scale back our activity during the second quarter as we adjust to the lower crude oil pricing environment. We reduced the number of drilling rigs on our lands from 12 in late 2014 to five currently. In addition, the number of frac crews has been reduced from three in late 2014 to one or two currently.

During the second quarter, 40 (11.6 net) wells were brought onstream, as compared to 52 (13.2 net) wells during the first quarter. Of the 40 wells that commenced production during the second quarter, 27 wells have been producing for more than 30 days and have established an average 30-day initial production rate of approximately 1,200 boe/d. As at June 30, 2015, we had 83 (20.3 net) wells awaiting completion.

In addition to targeting the Lower Eagle Ford formation, we are now actively delineating the Austin Chalk formation. The number of wells on our lands producing from the Austin Chalk is now 37 (10.7 net) with an average 30-day initial production rate of approximately 1,000 boe/d.

Additional advancements have been made to delineate the multi-zone development potential of our Sugarkane acreage. We have initiated "stack and frac" pilots which target up to three zones in the Eagle Ford formation in addition to the overlying Austin Chalk. Recent production data from two pads (a total of nine wells) that targeted three zones achieved 30-day initial production rates per well ranging from 900 to 1,600 boe/d. We now have eleven multi-zone projects in various stages of execution and production.

Canadian Operations

Production in Canada averaged 45,264 boe/d (85% oil and NGL) during Q2/2015, as compared to 49,634 boe/d in Q1/2015. The reduced volumes in Canada are a result of lower drilling activity, the decommissioning of our Gemini steam-assisted gravity drainage pilot project and uneconomic production that we have shut-in. Capital expenditures for our Canadian assets in Q2/2015 totaled $7.7 million, down from $21.3 million in Q1/2015.

At Lloydminster, we drilled two (2.0 net) horizontal wells. At Peace River, no drilling occurred in Q2/2015. During the quarter, the commissioning of Phase One of the Genalta Peace River Power Centre was completed resulting in Baytex delivering approximately 3.5 mmcf/d of natural gas to the facility for the purpose of generating electricity. In Q3/2015, Phase Two of the project is anticipated to be commissioned, resulting in the conservation of an additional 0.7 mmcf/d of natural gas and total electrical generation equivalent to the needs of over 23,000 homes in Alberta.

Financial Review

We generated FFO of $158.0 million ($0.77 per share) in Q2/2015, compared to $160.2 million ($0.95 per share) in Q1/2015. The variance is largely due to a decrease in realized financial derivative gains of $61.7 million, offset by higher revenues associated with improved commodity prices. During the second quarter, we funded 100% of our exploration and development expenditures and cash dividends with funds from operations. We recorded a net loss in Q2/2015 of $27.0 million ($0.13 per share) compared to a net loss of $175.9 million ($1.04 per share) in Q1/2015. The reduction in our net loss is largely due to higher revenues associated with improved commodity prices combined with a reversal of some of the negative movements on our U.S. dollar denominated debt due to a modest strengthening of the Canadian dollar in Q2/2015 after a significant weakening in Q1/2015.

In Q2/2015, we experienced an improvement in commodity prices with our realized oil and NGL price increasing 20% to $43.68/bbl, versus $36.40/bbl in Q1/2015. The average price for West Texas Intermediate ("WTI") increased to US$57.94/bbl during the quarter, as compared to US$48.64/bbl in Q1/2015 and the discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, narrowed to US$11.59/bbl in Q2/2015, as compared to US$14.73/bbl in Q1/2015. Subsequent to quarter-end, WCS differentials have widened with the August index averaging US$13.41/bbl. We expect WCS differentials to narrow in the coming months as improved market access is expected to reduce current inventory levels. The premium for Louisiana Light Sweet crude oil ("LLS"), relative to WTI, also widened to US$4.44/bbl in Q2/2015, as compared to US$1.91/bbl in Q1/2015.

We recognized a $0.6 million recovery of current income tax expense in Q2/2015. Through the first six months of 2015, we have recognized current income tax expense of $16.4 million. We forecast cash income taxes in 2015 at an effective tax rate of approximately 3-5% of pre-tax funds from operations. Substantially all of our estimated current income tax expense for 2015 has been recognized in the first half of 2015.

We generated an operating netback in Q2/2015 of $20.66/boe ($25.85/boe including financial derivatives gains). Our Canadian operations generated an operating netback of $16.48/boe while the Eagle Ford generated an operating netback of $25.45/boe. Our Eagle Ford assets are located in south Texas and are proximal to Gulf Coast crude oil markets with established transportation systems, resulting in strong realized prices. Our light oil and condensate production in the Eagle Ford is priced primarily off a LLS benchmark which typically trades at a premium to WTI. This strong pricing, combined with low cash costs, contributed positively to our operating netback in Q2/2015. The table below provides a summary of our operating netbacks for the periods noted.

	Three Months Ended June 30, 2015			Three Months Ended June 30, 2014	
($ per boe)	Canada	Eagle Ford	Total	Total	Change
Sales Price	$ 40.43	$ 46.67	$ 43.34	$ 75.06	(42%)
Less:					
Royalties	6.87	13.79	10.10	18.36	(45%)
Production and operating expenses	13.45	7.43[1]	10.64	12.51	(15%)
Transportation expenses	3.63	–	1.94	3.45	(44%)
Operating netback	$ 16.48	$ 25.45	$ 20.66	$ 40.74	(48%)
Financial derivatives gain (loss)	–	–	5.19	(2.28)	–%
Operating netback after financial derivatives	$ 16.48	$ 25.45	$ 25.85	$ 38.46	(32%)

(1) In the Eagle Ford, transportation expenses are included in production and operating expenses.

Risk Management

We employ a comprehensive risk management program which is intended to reduce some of the volatility in our FFO. In Q2/2015, we realized financial derivatives gains of $40.1 million, primarily due to crude oil prices being at levels significantly below those set in our fixed price contracts, which were partially offset by the settlement of our out-of-money foreign exchange contracts.

For Q3/2015, we have entered into hedges on approximately 24% of our net WTI exposure with 17% fixed at US$79.86/bbl and 7% receiving WTI plus US$10.00/bbl when WTI is below US$80.00/bbl. The unrealized financial derivatives gain with respect to our WTI hedges as at June 30, 2015 was $45.7 million. The following table summarizes our WTI hedges in place as at July 29, 2015.

	Q3/2015	Q4/2015	Last 6 Months 2015	Full-Year 2016
Fixed Hedges				
Volumes (bbl/d)	8,000	9,000	8,500	6,250
Hedge (%)[1]	17%	19%	18%	13%
Price (US$/bbl)	$79.86	$78.25	$79.01	$63.64
Floating Hedges				
Volumes (bbl/d)	3,312	–	1,656	–
Hedge (%)[1]	7%	–	4%	–
Price (US$/bbl)[2]	WTI + $10.00	–	WTI + $10.00	–
Total Hedge Volume				
Volumes (bbl/d)	11,312	9,000	10,156	6,250
Hedge (%)[1]	24%	19%	22%	13%

(1) Percentage of hedged volumes is based on the mid-point of our 2015 production guidance (excluding NGL), net of royalties.

(2) Hedges reflect our exposure when WTI is less than US$80/bbl.

As part of our hedging program, we also focus on opportunities to mitigate the volatility in WCS price differentials by transporting crude oil to markets by rail when economics warrant. We have no fixed investment or take or pay obligations to transport crude oil by rail and infrastructure around our core heavy oil producing regions allows for optimization between rail and pipe. In Q2/2015, approximately 18,000 bbl/d of our heavy oil volumes were delivered to market by rail, down 18% from the previous quarter. For Q3/2015, we expect to deliver approximately 15,000 bbl/d of our heavy oil volumes to market by rail as we optimize our heavy oil netbacks.

Financial Liquidity

We have taken several steps to maintain strong levels of financial liquidity this year, including evaluating our level and timing of capital spending, negotiating cost savings with service providers and completing an equity financing. On April 2, 2015, we issued 36,455,000 common shares at a price of $17.35 per share for net proceeds of approximately $606 million, which were used to reduce bank indebtedness.

Total monetary debt at June 30, 2015 was $1.82 billion, comprised of a bank loan of $192 million, long-term debt of $1.49 billion, and a working capital deficiency of $137 million. The decrease in total monetary debt at June 30, 2015, as compared to March 31, 2015, was primarily due to the application of the net proceeds from the equity financing to the bank loan.

We have unsecured revolving credit facilities consisting of a $1.0 billion Canadian facility and a US$200 million U.S. facility. During the second quarter, we extended the maturity date of these facilities to June 2019 (from June 2018 previously). These facilities do not require any mandatory principal payments prior to maturity and can be further extended beyond June 2019 with the consent of the lenders. As at June 30, 2015, we had approximately $1.05 billion in undrawn capacity on these facilities.

Amendments made to the financial covenants contained in our unsecured revolving credit facilities in February 2015 provide us with increased financial flexibility. As at June 30, 2015, our Senior Debt[(1)] to Bank EBITDA[(2)] ratio (twelve months trailing) is 1.72:1.00. Our revised financial covenants allow this ratio to reach a maximum of 4.75:1.00 through June 2016 and 4.50:1.00 through December 2016.

Conclusion

Given the current low crude oil price environment, we remain focused on prudently managing our operations to maintain strong levels of financial liquidity. The execution of our capital program has yielded impressive results in the Eagle Ford as we advance the multi-zone development potential of our acreage. In Canada, our assets continue to perform as expected with limited capital investment. Through negotiated cost savings with service providers, our portfolio of development opportunities in the Eagle Ford, Peace River and Lloydminster continue to provide attractive returns.

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
July 30, 2015

(1) "Senior debt" is defined as the sum of the principal amount of our bank loan and long-term debt.

(2) Bank EBITDA is a non-GAAP measure calculated based on terms and definitions set out in the credit agreement which adjusts net income for financing costs, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, amortization, impairment, exploration expenses, unrealized gains and losses on financial derivatives and foreign exchange, and share-based compensation) and acquisition and disposition activity and is calculated based on a trailing twelve month basis.

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, 2015. This information is provided as of July 29, 2015. 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 2014. 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, 2015, its audited comparative consolidated financial statements for the years ended December 31, 2014 and 2013, together with the accompanying notes and its Annual Information Form for the year ended December 31, 2014. 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 this 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 ("DRIP")) 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)) and the principal amount of both the long-term debt and the bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities. See "Liquidity, Capital Resources and Risk Management" for a calculation of total monetary debt.

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. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

SECOND QUARTER HIGHLIGHTS

During the second quarter of 2015, we experienced an improvement in commodity prices over the first quarter of 2015. The price of West Texas Intermediate oil ("WTI") averaged US$57.94/bbl, up US$9.30/bbl from the first quarter of 2015 but down 44% from the second quarter in 2014. The Western Canadian Select ("WCS") differential discount narrowed to US$11.59/bbl and the Louisiana Light Sweet ("LLS") differential premium widened to US$4.44/bbl during the second quarter of 2015 compared to US$14.73/bbl and US$1.91/bbl, respectively, in the first quarter. As a result of these price improvements, the second quarter realized heavy oil price increased 56% and realized light oil price increased 24% over the first quarter of 2015. Our hedging contracts mitigated some of the drop in commodity prices from 2014 as we realized financial derivative gains of $48.8 million on our oil contracts during the quarter. The average WTI price for the six months ended June 30, 2015 was US$53.29/bbl, 47% lower than the average WTI price for the first half of 2014. Prices for natural gas were down slightly from the first quarter of 2015, but were 37% lower than the second quarter of 2014. The average CAD/USD dollar exchange rate was $0.14 weaker in the first half of 2015 than in the same period of 2014, which has mitigated some of the decline in the commodity prices.

The operating results of the Company, in particular, the U.S. division, are significantly different in 2015 than in 2014, as we closed the acquisition of the Eagle Ford assets on June 11, 2014 and sold the North Dakota assets in September 2014. Average production for the three months ended June 30, 2015 was 84,812 boe/d, an increase of 27% compared to the same period in 2014 mainly due to the acquisition of the Eagle Ford assets. Canadian production was 45,264 boe/d for the second quarter of 2015, representing a decline of 9% from the first quarter of 2015 and a decline of 21% or 12,182 boe/d compared to the second quarter of 2014. Reduced capital spending levels for the past year, combined with shut-in uneconomic production and the 2014 property divestments account for the drop in production levels. For the six month period ended June 30, 2015, Canadian production is down 17% to 47,437 boe/d compared to the same period in 2014. U.S. production of 39,548 boe/d in the second quarter of 2015 was 316% higher than in the second quarter of 2014 due to the acquisition, but 4% lower than production in the first quarter of 2015 as we began to experience the effects of reduced capital activity over the past six months on our Eagle Ford assets. The decline in production in both Canada and the U.S. was expected and remains within our annual guidance range of 84,000 to 88,000 boe/d.

We reduced capital spending in the second quarter of 2015 to $106.0 million, down $41.4 million from the first quarter of 2015 and down $42.9 million from the $148.9 million spent in the second quarter of 2014. These reductions were in response to the sharp drop in crude oil prices and were achieved by reducing drilling activity and negotiating cost reductions from service providers. In the second quarter of 2015, $98.3 million of our capital spending was directed to the Eagle Ford assets. The second quarter capital investment program in the Eagle Ford was down from $126.2 million in the first quarter of 2015 and $149.5 million in the fourth quarter of 2014 due to reduced rig counts and frac crews.

Funds from operations ("FFO") for the quarter were $158.0 million compared to $165.5 million for the second quarter of 2014 and $160.2 million for the first quarter of 2015, with the decrease from 2014 due to lower commodity prices.

For the six months ended June 30, 2015, FFO was $318.3 million, down only 5.3% from the same period in 2014 as we only had 20 days of operations from the Eagle Ford assets in 2014.

On April 2, 2015, we completed an equity financing, issuing 36,455,000 common shares at a price of $17.35 per share for aggregate gross proceeds of approximately $632.5 million. The net proceeds of $606.0 million were used to reduce bank indebtedness. Total monetary debt has decreased to $1.8 billion at June 30, 2015, as compared to $2.3 billion at December 31, 2014 and $2.4 billion at March 31, 2015. We also extended the revolving period under our bank credit facilities to June 4, 2019 from June 4, 2018.

Starting with the June 2015 dividend, we added a second reinvestment option to our dividend reinvestment plan. Under the Premium Dividend™ Component, eligible shareholders can reinvest their dividends in new shares of Baytex at a 3% discount to the average market price, with the new shares being exchanged for a cash payment equal to 101% of the reinvested dividend amount.

U.S. RESULTS – IMPACT OF 2014 ACQUISITION AND DISPOSITION ACTIVITY

In 2015, the U.S. division is comprised of the Eagle Ford assets. The results of operations for the U.S. division in 2014 includes the Bakken assets in North Dakota, which were disposed of on September 24, 2014, and the Eagle Ford assets in Texas, which were acquired on June 11, 2014. This table bifurcates the U.S. division by area to better demonstrate the impact of the 2014 acquisition and disposition activity on the U.S. results. Further disclosure on the U.S. division is contained in the sections which follow.

	Three Months Ended June 30					
	2015			2014		
Daily Production	**Eagle Ford**	**North Dakota**	**Total**	Eagle Ford	North Dakota	Total
Liquids (bbl/d)						
Light oil and condensate	**23,999**	**–**	**23,999**	4,113	3,102	7,215
NGL	**7,147**	**–**	**7,147**	920	133	1,053
Total liquids (bbl/d)	**31,146**	**–**	**31,146**	5,033	3,235	8,268
Natural gas (mcf/d)	**50,414**	**–**	**50,414**	6,444	878	7,322
Total production (boe/d)	**39,548**	**–**	**39,548**	6,107	3,381	9,488
($ thousands except for % and per boe amounts)						
Revenue	**$ 167,986**	**$ –**	**$ 167,986**	$ 47,491	$ 28,923	$ 76,414
Royalties	**49,628**	**–**	**49,628**	13,769	9,327	23,096
Production and operating expenses	**26,739**	**–**	**26,739**	3,737	4,136	7,873
Operating income	**$ 91,619**	**$ –**	**$ 91,619**	$ 29,985	$ 15,460	$ 45,445
Realized price per boe	**$ 46.67**	**$ –**	**$ 46.67**	$ 84.72	$ 93.98	$ 88.02
Average royalty rate	**29.5%**	**–%**	**29.5%**	29.2%	32.2%	30.4%
Production and operating expenses per boe	**$ 7.43**	**$ –**	**$ 7.43**	$ 6.72	$ 13.44	$ 9.12

	Six Months Ended June 30					
	2015			2014		
Daily Production	**Eagle Ford**	**North Dakota**	**Total**	Eagle Ford	North Dakota	Total
Liquids (bbl/d)						
Light oil and condensate	**24,976**	**–**	**24,976**	2,068	2,930	4,998
NGL	**7,066**	**–**	**7,066**	462	163	625
Total liquids (bbl/d)	**32,042**	**–**	**32,042**	2,530	3,093	5,623
Natural gas (mcf/d)	**49,589**	**–**	**49,589**	3,240	871	4,111
Total production (boe/d)	**40,307**	**–**	**40,307**	3,070	3,238	6,308
($ thousands except for % and per boe amounts)						
Revenue	**$ 318,957**	**$ –**	**$ 318,957**	$ 47,491	$ 54,724	$ 102,215
Royalties	**92,916**	**–**	**92,916**	13,769	18,165	31,934
Production and operating expenses	**53,920**	**–**	**53,920**	3,737	9,038	12,775
Operating income	**$ 172,121**	**$ –**	**$ 172,121**	$ 29,985	$ 27,521	$ 57,506
Realized price per boe	**$ 43.71**	**$ –**	**$ 43.71**	$ 84.72	$ 93.38	$ 89.16
Average royalty rate	**29.1%**	**–%**	**29.1%**	29.2%	33.2%	31.4%
Production and operating expenses per boe	**$ 7.39**	**$ –**	**$ 7.39**	$ 6.72	$ 15.42	$ 11.19

U.S. production for the three and six months ended June 30, 2015 was 39,548 boe/d and 40,307 boe/d, respectively, representing an increase of 30,060 boe/d and 33,999 boe/d, respectively, as compared to the same periods in 2014. The increases were mainly due to the inclusion of the Eagle Ford production for 2015 as compared to only 20 days of production subsequent to the acquisition on June 11, 2014, partially offset by the disposition of the North Dakota assets on September 24, 2014. Eagle Ford production for the three and six months ended June 30, 2015 increased 11,765 boe/d and 12,524 boe/d, respectively, when compared to average production of 27,783 boe/d during the 20 days in June 2014 following the acquisition, reflecting continued growth from the successful development program.

Revenue for the three months ended June 30, 2015 of $168.0 million increased by $91.6 million compared to the same period in 2014 due to the increase in production, offset by a 47% decrease in realized pricing resulting from the overall drop in oil prices experienced since late 2014. Revenue for the six months ended June 30, 2015 of $319.0 million increased by $216.7 million compared to the same period in 2014 due to the increase in production, offset by a 51% decrease in realized pricing.

Royalties for the three and six months ended June 30, 2015 increased $26.5 million and $61.0 million, respectively, compared to the same periods in 2014 due to increased revenues. Royalty rates for the three and six months ended June 30, 2015 compared to the same periods in 2014 both decreased due to the sale of our North Dakota properties which carried higher royalty rates. Eagle Ford royalty rates were consistent with the prior year as royalty rates in this area do not vary with commodity pricing.

Production and operating expenses for the three and six months ended June 30, 2015 increased $18.9 million and $41.1 million, respectively, compared to the same periods in 2014 due to increased production volumes. Production and operating expenses per boe have decreased over the same periods in 2014 due to the shift in production to the lower cost Eagle Ford assets compared to our historic North Dakota properties. On a per boe basis, Eagle Ford production and operating expenses for both the three and six months ended June 30, 2015, of $7.43/boe and $7.39/boe, respectively, are largely consistent with the same periods in 2014.

RESULTS OF OPERATIONS

The Canadian division includes the heavy oil assets in Peace River and Lloydminster and the conventional oil and natural gas assets in Western Canada. The U.S. division includes the Bakken assets in North Dakota up to the date of disposition on September 24, 2014 and the Eagle Ford assets in Texas subsequent to the date of acquisition on June 11, 2014.

Production

	Three Months Ended June 30					
	2015			2014		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil(1)	35,439	–	35,439	45,986	–	45,986
Light oil and condensate	1,900	23,999	25,899	2,650	7,215	9,865
NGL	1,085	7,147	8,232	1,422	1,053	2,475
Total liquids (bbl/d)	38,424	31,146	69,570	50,058	8,268	58,326
Natural gas (mcf/d)	41,042	50,414	91,456	44,323	7,322	51,645
Total production (boe/d)	45,264	39,548	84,812	57,445	9,488	66,934
Production Mix						
Heavy oil	78%	–%	41%	80%	–%	69%
Light oil and condensate	4%	61%	31%	5%	76%	15%
NGL	3%	18%	10%	2%	11%	3%
Natural gas	15%	21%	18%	13%	13%	13%

	Six Months Ended June 30					
	2015			2014		
Daily Production	Canada	U.S.	Total	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil(1)	37,339	–	37,339	45,611	–	45,611
Light oil and condensate	1,995	24,976	26,971	2,682	4,998	7,680
NGL	1,162	7,066	8,228	1,607	625	2,232
Total liquids (bbl/d)	40,496	32,042	72,538	49,900	5,623	55,523
Natural gas (mcf/d)	41,645	49,589	91,234	42,184	4,111	46,295
Total production (boe/d)	47,437	40,307	87,744	56,931	6,308	63,239
Production Mix						
Heavy oil	79%	–%	43%	80%	–%	72%
Light oil and condensate	4%	62%	31%	5%	79%	12%
NGL	2%	18%	9%	3%	10%	4%
Natural gas	15%	20%	17%	12%	11%	12%

(1) *Heavy oil sales volumes may differ from reported production volumes due to changes in our heavy oil inventory.*

Average production for the three months ended June 30, 2015 was 84,812 boe/d, an increase of 27% or 17,878 boe/d, compared to the same period in 2014. The overall increase is due to the acquisition and disposition events discussed in the U.S. results section. Canadian production of 45,264 boe/d decreased 21%, or 12,182 boe/d, primarily due to declines resulting from reduced capital spending over the past twelve months.

Additionally in Canada, approximately 1,400 boe/d of production was shut-in for economic reasons in the current quarter and approximately 1,250 boe/d of production was divested in late 2014.

Average production for the six months ended June 30, 2015 was 87,744 boe/d, an increase of 39% or 24,505 boe/d, compared to the same period in 2014. The overall increase is due to the acquisition and disposition events discussed in the U.S. results section. Canadian production of 47,437 boe/d decreased 17% or 9,494 boe/d compared to the first half of 2014, primarily due to declines resulting from reduced capital spending over the past twelve months, approximately 1,050 boe/d of production that was shut-in for economic reasons in the first half of 2015 and approximately 1,250 boe/d of production was divested in late 2014.

Commodity Prices

The prices received for our crude oil and natural gas production directly impact our earnings, funds from operations and our financial position.

Crude Oil

For the three months ended June 30, 2015, the price of WTI averaged US$57.94/bbl, a 44% decrease from the average WTI price of US$102.99/bbl in the second quarter of 2014 but a 19% increase from US$48.64/bbl in the first quarter of 2015. For the six months ended June 30, 2015, the price of WTI averaged US$53.29/bbl, a 47% decrease from the average WTI price of US$100.84/bbl in the same period in 2014. The low prices experienced during the three and six months ended June 30, 2015, as compared to the same periods in 2014, was brought on by the ongoing global over supply of oil stemming from high North American production growth and the decision by the Organization of Petroleum Exporting Countries (OPEC) to step away from its role as the swing producer.

For the three and six months ended June 30, 2015, improved market access allowed Canadian heavy oil to reach and exceed pipeline parity values with international heavy oils such as Maya in the Gulf of Mexico. The discount for Canadian heavy oil is measured by the WCS price differential to WTI. The WCS differential narrowed during the second quarter of 2015 due to improved market access, stronger refinery margins and higher refinery runs. This resulted in the WCS differential decreasing from US$14.73/bbl in the first quarter of 2015 to US$11.59/bbl in the second quarter of 2015. The increase in WTI, coupled with the decrease in the WCS differential resulted in an increase in the WCS price of US$12.44/bbl, or 37%, in the second quarter of 2015 compared to the first quarter of 2015. For the three and six months ended June 30, 2015, the WCS heavy oil differential averaged US$11.59/bbl and US$13.15/bbl, respectively, down from US$20.04/bbl and US$21.59/bbl, respectively, in the same periods of 2014.

Natural Gas

For the three and six months ended June 30, 2015, the AECO natural gas price averaged $2.67/mcf and $2.81/mcf, respectively, an approximate 40% decrease compared to $4.68/mcf and $4.72/mcf for the respective comparative periods of 2014. For the three and six months ended June 30, 2015, the NYMEX natural gas prices averaged US$2.64/mmbtu and US$2.81/mmbtu, respectively, an approximate 40% decrease compared to US$4.67/mmbtu and US$4.80/mmbtu for the respective periods in 2014. The decrease in natural gas prices on both indices was driven by exceptionally strong production growth in the U.S.

The following tables compare selected benchmark prices and our average realized selling prices for the three and six months ended June 30, 2015 and 2014.

	Three Months Ended June 30			Six Months Ended June 30		
	2015	2014	Change	2015	2014	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	$ 57.94	$ 102.99	(44%)	$ 53.29	$ 100.84	(47%)
WCS heavy oil (US$/bbl)[2]	$ 46.35	$ 82.95	(44%)	$ 40.14	$ 79.25	(49%)
Heavy oil differential[3]	20%	19%		25%	22%	
LLS oil (US$/bbl)[4]	$ 62.38	$ 106.81	(42%)	$ 56.47	$ 105.86	(47%)
CAD/USD average exchange rate	1.2294	1.0894	13%	1.2353	1.0964	13%
Edmonton par oil ($/bbl)	$ 67.72	$ 106.68	(37%)	$ 59.84	$ 103.43	(42%)
AECO natural gas price ($/mcf)[5]	$ 2.67	$ 4.68	(43%)	$ 2.81	$ 4.72	(40%)
NYMEX natural gas price (US$/mmbtu)[6]	$ 2.64	$ 4.67	(43%)	$ 2.81	$ 4.80	(41%)

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.

(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 on a monthly weighted average basis.

(4) LLS refers to the Argus trade month average.

(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").

(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended June 30					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	$ 44.59	$ –	$ 44.59	$ 79.26	$ –	$ 79.26
Light oil and condensate ($/bbl)	62.20	65.34	65.11	100.26	105.59	104.16
NGL ($/bbl)	23.05	14.67	15.78	42.96	33.04	38.74
Natural gas ($/mcf)	2.61	3.43	3.06	4.77	5.26	4.84
Weighted average ($/boe)[2]	$ 40.43	$ 46.67	$ 43.34	$ 72.85	$ 88.02	$ 75.06

	Six Months Ended June 30					
	2015			2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Average Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	$ 36.21	$ –	$ 36.21	$ 75.26	$ –	$ 75.26
Light oil and condensate ($/bbl)	54.72	58.81	58.50	97.39	103.24	101.20
NGL ($/bbl)	23.65	16.55	17.55	49.56	38.07	46.34
Natural gas ($/mcf)	2.64	3.56	3.14	4.96	5.52	5.01
Weighted average ($/boe)[2]	$ 33.70	$ 43.71	$ 38.30	$ 69.97	$ 89.16	$ 71.92

(1) 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 pricing information in the table excludes the impact of financial derivatives.

(2) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.

Average Realized Sales Prices

Our realized heavy oil price for the three months ended June 30, 2015 was $44.59/bbl, or 78% of WCS, compared to $79.26/bbl, or 88% of WCS in 2014. Our realized heavy oil price for the six months ended June 30, 2015 was $36.21/bbl, or 73% of WCS, compared to $75.26/bbl, or 87% of WCS in 2014. For both comparatives, the decrease in realized heavy oil price was due to the overall decline in global crude oil prices while the decrease in the realized price relative to WCS was due to fixed price differentials that increase as a percentage of WCS as the price of WCS declines.

During the three months ended June 30, 2015, our Canadian average sales price for light oil and condensate was $62.20/bbl, down 38% from $100.26/bbl in 2014. This is largely in line with the 37% decrease in the benchmark Edmonton Par prices over the same period. U.S. light oil and condensate pricing for the three months ended June 30, 2015 was $65.34/bbl, down 38% from $105.59/bbl in the second quarter of 2014, largely in line with the 34% decrease in the LLS benchmark (as expressed in Canadian dollars) over the same period. During the six months ended June 30, 2015, our Canadian average sales price for light oil and condensate was $54.72/bbl, down 44% from $97.39/bbl in 2014, largely in line with the 42% decrease in Edmonton Par price over the same period. U.S. light oil and condensate pricing for the six months ended June 30, 2015 was $58.81/bbl, down 43% from $103.24/bbl in the first half of 2014, in line with the decline in the LLS benchmark (as expressed in Canadian dollars) over the same period.

We report our realized prices in Canadian dollars and the weakening of the Canadian dollar against the US dollar has offset some of the impact of the decline in commodity prices. For the three and six months ended June 30, 2015, the weakening Canadian dollar increased the Canadian dollar equivalent of WCS by $6.49/bbl and $5.58/bbl, respectively, and increased the Canadian dollar equivalent of WTI by $8.11/bbl and $7.40/bbl, respectively.

Our realized natural gas price for the three months ended June 30, 2015 was $3.06/mcf, down from $4.84/mcf in the second quarter of 2014 representing a 37% decrease. This is largely in line with the decreases in the AECO and NYMEX benchmarks of 43% over the same periods. Our realized natural gas price for the six months ended June 30, 2015 was $3.14/mcf, down from $5.01/mcf during the same period in 2014, representing a decrease of 37%. This is largely in line with the decreases in the AECO and NYMEX benchmarks over the same periods.

Gross Revenues

	Three Months Ended June 30					
	2015			2014		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil revenue						
Heavy oil	**$ 143,626**	**$ –**	**$ 143,626**	$ 333,518	$ –	$ 333,518
Light oil and condensate	**10,752**	**142,686**	**153,438**	24,170	69,326	93,496
NGL	**2,276**	**9,542**	**11,818**	5,564	3,166	8,730
Total oil revenue	**156,654**	**152,228**	**308,882**	363,252	72,492	435,744
Natural gas revenue	**9,736**	**15,723**	**25,459**	19,257	3,507	22,764
Total oil and natural gas revenue	**166,390**	**167,951**	**334,341**	382,509	75,999	458,508
Other income	**2,594**	**35**	**2,629**	–	415	415
Heavy oil blending revenue	**8,462**	**–**	**8,462**	17,481	–	17,481
Total petroleum and natural gas revenues	**$ 177,446**	**$ 167,986**	**$ 345,432**	$ 399,990	$ 76,414	$ 476,404

	Six Months Ended June 30					
	2015			2014		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil revenue						
Heavy oil	**$ 244,482**	**$ –**	**$ 244,482**	$ 622,730	$ –	$ 622,730
Light oil and condensate	**19,752**	**265,843**	**285,595**	47,278	93,386	140,664
NGL	**4,972**	**21,167**	**26,139**	14,418	4,310	18,728
Total oil revenue	**269,206**	**287,010**	**556,216**	684,426	97,696	782,122
Natural gas revenue	**19,922**	**31,912**	**51,834**	37,855	4,104	41,959
Total oil and natural gas revenue	**289,128**	**318,922**	**608,050**	722,281	101,800	824,081
Other income	**4,826**	**35**	**4,861**	–	415	415
Heavy oil blending revenue	**18,136**	**–**	**18,136**	37,717	–	37,717
Total petroleum and natural gas revenues	**$ 312,090**	**$ 318,957**	**$ 631,047**	$ 759,998	$ 102,215	$ 862,213

Total petroleum and natural gas revenues for the three months ended June 30, 2015 of $345.4 million decreased $131.0 million from the second quarter of 2014 as the decline in commodity prices more than offset the increased production volumes. In Canada, petroleum and natural gas revenues for the three months ended June 30, 2015 totaled $177.4 million, a decrease of $222.5 million compared to the same period in 2014 due to lower realized prices on all products combined with a 23% reduction in liquids production volumes. Petroleum and natural gas revenues of $168.0 million in the U.S. increased from prior year due to the acquisition of the Eagle Ford assets. See the U.S. results section for detail.

Total petroleum and natural gas revenues for the six months ended June 30, 2015 of $631.0 million decreased $231.2 million from the six months ended June 30, 2014 as the decline in commodity prices more than offset the increase in production volumes. In Canada, petroleum and natural gas revenues for the six months totaled $312.1 million, a decrease of $447.9 million compared to the same period in 2014 due to lower realized prices on all products combined with a 19% reduction in liquids production volumes. Petroleum and natural gas revenues of $319.0 million in the U.S. increased from prior year due to the acquisition of the Eagle Ford assets. See the U.S. results section for detail.

Heavy oil blending revenue for the three and six months ended June 30, 2015 of $8.5 million and $18.1 million, respectively, was 52% lower than the same periods in 2014. The decrease in heavy oil production coupled with the increase in transportation by rail has resulted in lower volumes of diluent being used and sold. In addition, the price of blending diluent has declined in line with the decrease in the price of oil.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on netbacks less capital investment and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following tables summarize our royalties and royalty rates for the three and six months ended June 30, 2015 and 2014.

	Three Months Ended June 30					
	2015			2014		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 28,258	$ 49,628	$ 77,886	$ 89,186	$ 23,096	$ 112,282
Average royalty rate[1]	17.0%	29.5%	23.3%	23.3%	30.4%	24.5%
Royalty rate per boe	$ 6.87	$ 13.79	$ 10.10	$ 16.98	$ 26.75	$ 18.36

	Six Months Ended June 30					
	2015			2014		
($ thousands except for % and per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Royalties	$ 41,677	$ 92,916	$ 134,593	$ 155,228	$ 31,934	$ 187,162
Average royalty rate[1]	14.4%	29.1%	22.1%	21.5%	31.4%	22.7%
Royalty rate per boe	$ 4.86	$ 12.74	$ 8.48	$ 15.04	$ 27.97	$ 16.33

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

Total royalties for the three months ended June 30, 2015 of $77.9 million decreased 31%, or $34.4 million from 2014, mainly due to the decline in revenues. Canadian royalties have decreased to 17.0% of revenue for the three months ended June 30, 2015, compared to 23.3% of revenue in 2014 as the majority of crown royalty rates are price sensitive and lower commodity prices have resulted in lower crown royalty rates. The second quarter includes a $1.4 million charge related to 2014 crown royalties for natural gas which offsets some of the decline in rates. U.S. royalties have increased $26.5 million due to the acquisition and disposition events discussed in the U.S. results section.

Total royalties for the six months ended June 30, 2015 of $134.6 million decreased 28%, or $52.6 million from 2014, mainly due to the decline in revenues. Canadian royalties have decreased to 14.4% of revenue for the six months ended June 30, 2015, compared to 21.5% of revenue in 2014 as the majority of crown royalty rates are price sensitive and lower commodity prices have resulted in lower crown royalty rates. The Canadian royalty expense also includes a net adjustment of $1.2 million that reduced 2015 costs and primarily relates to 2014 production. The six month average royalty rate for Canada of 14.4% is comprised of a 17.0% rate in the second quarter of 2015 and a 10.9% rate in the first quarter of 2015. The increase in the rate reflects an increased weighting in Canadian revenue in the second quarter towards heavy oil which carries a higher royalty burden than other products. In addition, the effective royalty rate for heavy oil is price sensitive, especially within the commodity price range experienced in the first six months of 2015. U.S. royalties have increased $61.0 million compared to the same period in 2014 due to the acquisition and disposition events discussed in the U.S. results section.

Production and Operating Expenses

	Three Months Ended June 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Production and operating expenses	$ 55,341	$ 26,739	$ 82,080	$ 68,623	$ 7,873	$ 76,496
Production and operating expenses per boe	$ 13.45	$ 7.43	$ 10.64	$ 13.07	$ 9.12	$ 12.51

	Six Months Ended June 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.(1)	Total	Canada	U.S.(1)	Total
Production and operating expenses	$ 115,915	$ 53,920	$ 169,835	$ 132,556	$ 12,775	$ 145,331
Production and operating expenses per boe	$ 13.51	$ 7.39	$ 10.70	$ 12.84	$ 11.19	$ 12.68

(1) Production and operating expenses related to the Eagle Ford assets include transportation expenses.

Production and operating expenses of $82.1 million and $169.8 million for the three and six months ended June 30, 2015 increased by $5.6 million and $24.5 million, respectively, compared to the same periods in 2014. On a per boe basis, however, production and operating expenses for the three and six months ended June 30, 2015 are down to $10.64/boe and $10.70/boe, respectively, compared to $12.51/boe and $12.68/boe for the same periods in 2014. The decreases in the cost per boe are due to the acquisition of the Eagle Ford properties which have lower costs and comprise approximately 45% of our total production in 2015.

Canadian production and operating expenses have decreased $13.3 million and $16.6 million for the three and six months ended June 30, 2015, respectively, compared to the same periods in 2014, reflecting decreased production volumes and cost saving initiatives. Canadian production and operating expenses per boe increased $0.38/boe and $0.67/boe for the three and six months ended June 30, 2015, respectively, compared to the same periods in 2014 due to the impact of fixed costs on lower production levels, partially offset by cost savings initiatives.

U.S. production and operating expenses per boe declined $1.69/boe and $3.80/boe, respectively, for the three and six months ended June 30, 2015, which reflects the shift in production to the lower cost Eagle Ford assets compared to our historic North Dakota properties. Eagle Ford operating costs for the three months ended June 30, 2015 were $7.43/boe, consistent with the first quarter of 2015, but lower than the last six months of 2014 due to cost savings negotiated from service providers and decreased workover expenditures.

Transportation and Blending Expenses

Transportation expenses include the costs to move production from the field to the sales point. The largest component of transportation expense relates to the movement of heavy oil to pipeline and rail terminals. In order to meet pipeline specifications and to facilitate its marketing, the heavy oil transported through pipelines requires blending to reduce its viscosity. The cost of blending diluent is recovered in the sale price of the blended product. However, heavy oil transported by rail does not require blending diluent.

The following tables compare our transportation and blending expenses for the three and six months ended June 30, 2015 and 2014.

	Three Months Ended June 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.[2]	Total	Canada	U.S.[2]	Total
Blending expenses	$ 8,462	$ –	$ 8,462	$ 17,481	$ –	$ 17,481
Transportation expenses	14,928	–	14,928	21,103	–	21,103
Total transportation and blending expenses	$ 23,390	$ –	$ 23,390	$ 38,584	$ –	$ 38,584
Transportation expenses per boe[1]	$ 3.63	$ –	$ 1.94	$ 4.02	$ –	$ 3.45

	Six Months Ended June 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.[2]	Total	Canada	U.S.[2]	Total
Blending expenses	$ 18,136	$ –	$ 18,136	$ 37,717	$ –	$ 37,717
Transportation expenses	30,876	–	30,876	45,770	–	45,770
Total transportation and blending expenses	$ 49,012	$ –	$ 49,012	$ 83,487	$ –	$ 83,487
Transportation expenses per boe[1]	$ 3.60	$ –	$ 1.94	$ 4.43	$ –	$ 3.99

(1) Transportation expenses per boe exclude the purchase of blending diluent.
(2) Transportation expenses related to the Eagle Ford assets are included in production and operating expenses.

Transportation expenses for the three months ended June 30, 2015 totaled $14.9 million, a decrease of 29%, or $6.2 million, compared to 2014. Transportation expenses for the six months ended June 30, 2015 totaled $30.9 million, a decrease of 33%, or $14.9 million, compared to 2014. The decreases for both comparative periods are due to lower heavy oil volumes, decreased fuel surcharges and various trucking optimization efforts.

Blending expenses for the three and six months ended June 30, 2015 have decreased $9.0 million and $19.6 million, respectively, compared to the same periods in 2014. Consistent with the decrease in heavy oil blending revenue, blending expenses decreased due to a decrease in both the price of blending diluent and the volume of diluent required.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize a series of financial derivative contracts which are intended to reduce some of the volatility in our operating cash flow. Financial derivatives are managed at the corporate level and are not allocated between divisions. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price on the date the contract matures. As the forward markets for commodities and currencies fluctuate and as new contracts are executed, changes in the fair value are reported as unrealized gains or losses in the period. Contracts in place at the beginning of the period which settle during the period will give rise to the reversal of the unrealized gain or loss recorded at the beginning of the period.

The following table summarizes the results of our financial derivative contracts for the three and six months ended June 30, 2015 and 2014.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2015**	2014	Change	**2015**	2014	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 48,784**	$ (12,054)	$ 60,838	**$ 156,811**	$ (10,441)	$ 167,252
Natural gas	**309**	(629)	938	**6,037**	(1,816)	7,853
Foreign currency	**(9,021)**	(1,231)	(7,790)	**(20,942)**	(3,266)	(17,676)
Interest	**–**	117	(117)	**–**	(4,021)	4,021
Total	**$ 40,072**	$ (13,797)	$ 53,869	**$ 141,906**	$ (19,544)	$ 161,450
Unrealized financial derivatives gain (loss)						
Crude oil	**$ (59,545)**	$ (33,034)	$ (26,511)	**$(129,124)**	$ (42,346)	$ (86,778)
Natural gas	**351**	795	(444)	**(4,647)**	(2,241)	(2,406)
Foreign currency	**14,036**	(15,043)	29,079	**(1,420)**	6,118	(7,538)
Interest and financing(1)	**3,419**	11,956	(8,537)	**5,280**	15,968	(10,688)
Total	**$ (41,739)**	$ (35,326)	$ (6,413)	**$(129,911)**	$ (22,501)	$ (107,410)
Total financial derivatives gain (loss)						
Crude oil	**$ (10,761)**	$ (45,088)	$ 34,327	**$ 27,687**	$ (52,787)	$ 80,474
Natural gas	**660**	166	494	**1,390**	(4,057)	5,447
Foreign currency	**5,015**	(16,274)	21,289	**(22,362)**	2,852	(25,214)
Interest and financing(1)	**3,419**	12,073	(8,654)	**5,280**	11,947	(6,667)
Total	**$ (1,667)**	$ (49,123)	$ 47,456	**$ 11,995**	$ (42,045)	$ 54,040

(1) Unrealized interest and financing derivative gain (loss) includes the change in fair value of the call options embedded in our senior unsecured notes.

The realized financial derivative gains of $40.1 million and $141.9 million for the three and six months ended June 30, 2015, respectively, relate mainly to crude oil prices being at levels significantly below those set in our fixed price contracts, partially offset by the settlement of our out-of-money foreign exchange contracts as the Canadian dollar weakened against the U.S. dollar prices set in the contracts.

The unrealized mark-to-market loss of $41.7 million for the three months ended June 30, 2015 is mainly due to the realization of previously recorded unrealized gains on our commodity contracts offset slightly by the strengthening Canadian dollar against the U.S. dollar at June 30, 2015 compared to March 31, 2015. The unrealized mark-to-market loss of $129.9 million for the six months ended June 30, 2015 is mainly due to realization of previously recorded unrealized gains on our commodity contracts.

A summary of the financial derivative contracts in place as at June 30, 2015 and the accounting treatment thereof are disclosed in note 17 to the consolidated financial statements.

Operating Netback

	Three Months Ended June 30					
	2015			2014		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	45,222	39,548	84,770	57,703	9,488	67,191
Operating netback[1]:						
Sales price	$ 40.43	$ 46.67	$ 43.34	$ 72.85	$ 88.02	$ 75.06
Less:						
Royalties	6.87	13.79	10.10	16.98	26.75	18.36
Production and operating expenses	13.45	7.43	10.64	13.07	9.12	12.51
Transportation expenses	3.63	–	1.94	4.02	–	3.45
Operating netback before financial derivatives	$ 16.48	$ 25.45	$ 20.66	$ 38.78	$ 52.15	$ 40.74
Financial derivatives gain (loss)[2]	–	–	5.19	–	–	(2.28)
Operating netback after financial derivatives	$ 16.48	$ 25.45	$ 25.85	$ 38.78	$ 52.15	$ 38.46

	Six Months Ended June 30					
	2015			2014		
($ per boe except for volume)	Canada	U.S.	Total	Canada	U.S.	Total
Sales volume (boe/d)	47,399	40,308	87,707	57,032	6,308	63,340
Operating netback[1]:						
Sales price	$ 33.70	$ 43.71	$ 38.30	$ 69.97	$ 89.16	$ 71.92
Less:						
Royalties	4.86	12.74	8.48	15.04	27.97	16.33
Production and operating expenses	13.51	7.39	10.70	12.84	11.19	12.68
Transportation expenses	3.60	–	1.94	4.43	–	3.99
Operating netback before financial derivatives	$ 11.73	$ 23.58	$ 17.18	$ 37.66	$ 50.00	$ 38.92
Financial derivatives gain (loss)[2]	–	–	8.94	–	–	(1.35)
Operating netback after financial derivatives	$ 11.73	$ 23.58	$ 26.12	$ 37.66	$ 50.00	$ 37.57

(1) Operating netback table includes revenues and costs associated with sulphur production.
(2) Financial derivatives reflect realized gains on commodity-related contracts only.

Exploration and Evaluation Expense

Exploration and evaluation expense includes the write-off of undeveloped lands and assets and will vary period to period depending on the scheduled expiry of leases and our assessment of the development potential of undeveloped land.

Exploration and evaluation expense was $2.2 million and $4.5 million for the three and six months ended June 30, 2015, respectively, compared to $3.9 million and $14.5 million for the three and six months ended June 30, 2014, respectively. The decrease in exploration and evaluation expense is primarily related to a decrease in expiration of undeveloped land leases and lands we no longer plan to exploit.

Depletion and Depreciation

	Three Months Ended June 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation[1]	$ 67,711	$ 92,820	$ 161,476	$ 77,011	$ 21,856	$ 99,591
Depletion and depreciation per boe	$ 16.45	$ 25.79	$ 20.93	$ 14.80	$ 25.37	$ 16.56

	Six Months Ended June 30					
	2015			2014		
($ thousands except for per boe)	Canada	U.S.	Total	Canada	U.S.	Total
Depletion and depreciation[1]	$ 142,828	$ 191,204	$ 335,603	$ 158,457	$ 28,466	$ 188,184
Depletion and depreciation per boe	$ 16.65	$ 26.21	$ 21.14	$ 15.46	$ 25.01	$ 16.41

(1) Total includes corporate depreciation.

Depletion and depreciation expense of $161.5 million and $335.6 million for the three and six months ended June 30, 2015 increased $61.9 million and $147.4 million, respectively, from the same periods in 2014. The increases for both comparative periods are mainly due to the acquisition of the Eagle Ford assets, slightly offset by the impact of the North Dakota sale combined with lower production volumes in Canada. The depletion rate per boe for the three and six months ended June 30, 2015 of $20.93/boe and $21.14/boe increased from $16.56/boe and $16.41/boe for same periods in 2014, respectively, mainly due to the Eagle Ford assets which have higher costs included in the depletable pool.

General and Administrative Expenses

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	2015	2014	Change	2015	2014	Change
General and administrative expenses	$ 15,557	$ 14,309	9%	$ 32,612	$ 26,208	24%
General and administrative expenses per boe	$ 2.02	$ 2.34	(14%)	$ 2.05	$ 2.29	(10%)

General and administrative expenses for the three and six months ended June 30, 2015 of $15.6 million and $32.6 million, respectively, increased $1.2 million and $6.4 million, respectively, compared to the same periods in 2014. The increases for both comparative periods are due to the addition of the Houston office to support our Eagle Ford operations and lower capital recoveries consistent with our lower capital spending in Canada. These increases were offset by spending reductions in response to the sharp drop in commodity prices, as well as the elimination of costs associated with the Denver office after the North Dakota asset sale.

On a per boe basis, general and administrative expenses have decreased in 2015 from 2014 for both the three and six month comparative periods, due to cost controls and the low incremental overhead associated with the acquired Eagle Ford assets.

Share-based Compensation Expense

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

Compensation expense related to the Share Award Incentive Plan remained constant at $8.2 million and $16.2 million for the three and six months ended June 30, 2015, respectively, compared to $8.2 million and $16.1 million for the same periods in 2014, respectively. Despite a lower fair value of share awards for 2015, share-based compensation remained relatively unchanged as the expense relating to the three and six months ended June 30, 2014 included larger credits for actual forfeitures, as compared to the current periods, causing the reduced expense in 2014.

Financing Costs

Financing costs include interest on bank loans and long-term debt, non-cash charges related to accretion of asset retirement obligations and the amortization of loan and debt financing costs.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for %)	**2015**	2014	Change	**2015**	2014	Change
Bank loan and other	**$ 3,345**	$ 4,566	(27%)	**$ 8,763**	$ 10,658	(18%)
Long-term debt	**21,879**	11,252	94%	**44,253**	16,008	176%
Accretion on asset retirement obligations	**1,548**	1,779	(13%)	**3,166**	3,520	(10%)
Financing costs	**$ 26,772**	$ 17,597	52%	**$ 56,182**	$ 30,186	86%

The increase in the three and six months ended June 30, 2015 financing costs compared to 2014 is due to higher outstanding debt levels mainly related to the acquisition of the Eagle Ford assets in June 2014. Financing costs related to the bank loan have decreased for the three and six months ended June 30, 2015 as compared to 2014 due to lower outstanding bank loan balances in 2015 as the $606 million net proceeds of the equity financing were used to pay down the bank loan in April 2015. Amendment fees on the credit facility of $0.7 million were included in financing costs for the three and six months ended June 30, 2015, as compared to no amendment fee in the same periods of 2014.

Foreign Exchange

Unrealized foreign exchange gains and losses are due to the change in the value of the long-term debt denominated in U.S. dollars which is caused by the movement of the Canadian dollar against the U.S. dollar during the period. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in the Canadian operations.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and exchange rates)	**2015**	2014	Change	**2015**	2014	Change
Unrealized foreign exchange (gain) loss	**$ (18,349)**	$ (21,379)	(14%)	**$ 82,967**	$ (14,923)	(656%)
Realized foreign exchange loss	**4,374**	2,924	50%	**113**	986	(89%)
Foreign exchange (gain) loss	**$ (13,975)**	$ (18,455)	(24%)	**$ 83,080**	$ (13,937)	(696%)
CAD/USD exchange rates:						
At beginning of period	**1.2683**	1.1053		**1.1601**	1.0636	
At end of period	**1.2474**	1.0676		**1.2474**	1.0676	

The unrealized foreign exchange gain of $18.3 million for the three months ended June 30, 2015 was primarily due to the revaluation of our U.S. dollar denominated senior unsecured notes (US$950 million principal amount) as the Canadian dollar strengthened against the U.S. dollar at June 30, 2015 as compared to March 31, 2015. The realized foreign exchange loss of $4.4 million for the three months ended June 30, 2015 was due to the settlement of certain U.S. dollar denominated interest payable. The foreign exchange loss of $83.1 million for the six months ended June 30, 2015 was due to the weakened Canadian dollar against the U.S. dollar at June 30, 2015 as compared to December 31, 2014.

Income Taxes

For the three months ended June 30, 2015, total income tax recovery of $12.9 million included $0.6 million of current income tax recovery and $12.3 million of deferred income tax recovery. For the three months ended June 30, 2014, total income tax expense of $19.7 million related entirely to deferred income tax.

For the six months ended June 30, 2015, total income tax recovery of $37.6 million included $16.4 million of current income tax expense and $54.0 million of deferred income tax recovery. For the six months ended June 30, 2014, total income tax expense of $40.1 million related entirely to deferred income tax.

The increase in current income tax expense in the current quarter, as compared to the second quarter of 2014, primarily relates to the increase in realized financial derivative gains and the increase in previously deferred income being taxed in the current period. On June 29, 2015, the general corporate income tax rate for Alberta increased to 12% from 10% effective July 1, 2015. On June 15, 2015, legislation was enacted in Texas that decreased the Texas Franchise Tax to 0.75% from 1% effective January 1, 2016. As a result of the changes, the Company's deferred income tax liability increased by $11 million at June 30, 2015.

In 2014, the Canada Revenue Agency ("CRA") advised Baytex that it was proposing to reassess certain subsidiaries of Baytex to deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2013. Baytex has filed its 2014 income tax return and intends to file its future tax returns on the same basis as the 2011 through 2013 tax returns, cumulatively claiming $591 million of non-capital losses. The Company believes that it should be entitled to deduct the non-capital losses, that its tax filings to-date are correct, and has formally responded with a letter to the CRA indicating the same. At this time, the CRA has not issued a reply to Baytex's letter. The Company expects to continue to defend the position as filed.

Net Income (Loss)

Net loss for the three months ended June 30, 2015 totaled $27.0 million compared to net income of $36.8 million in 2014. The decrease was due to lower operating netbacks, higher depletion expenses and financing costs, partially offset by lower financial derivatives loss and an income tax recovery.

Net loss for the six months ended June 30, 2015 totaled $202.9 million compared to net income of $84.6 million in 2014. The decrease was due to lower operating netbacks, higher unrealized foreign exchange losses on U.S. denominated debt, higher depletion expenses and financing costs, partially offset by higher financial derivatives gain and an income tax recovery.

Other Comprehensive Income

Other comprehensive income is comprised of the foreign currency translation adjustment on U.S. operations not recognized in profit or loss. The foreign currency translation loss of $41.7 million for the three months ended June 30, 2015 is due to the strengthening of the Canadian dollar against the U.S. dollar at June 30, 2015 (1.2474 CAD/USD) compared to the exchange rate on March 31, 2015 (1.2683 CAD/USD). The foreign currency translation gain of $199.3 million for the six months ended June 30, 2015 is due to the weakening of the Canadian dollar against the U.S. dollar at June 30, 2015 (1.2474 CAD/USD) compared to the exchange rate on December 31, 2014 (1.1601 CAD/USD).

Capital Expenditures

In the first half of 2015, our capital program has been significantly curtailed in response to low commodity prices with only minimal capital expenditures occurring and planned in Canada. In the U.S., activity levels have also slowed compared to the last half of 2014.

Capital expenditures for the three and six months ended June 30, 2015 and 2014 are summarized as follows:

	Three Months Ended June 30					
	2015			2014		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	$ 7,690	$ 98,320	$ 106,010	$ 97,805	$ 51,111	$ 148,916
Acquisitions, net of divestitures[1]	1,410	(240)	1,170	8,737	2,912,108	2,920,845
Total oil and natural gas capital expenditures	$ 9,100	$ 98,080	$ 107,180	$ 106,542	$2,963,219	$3,069,761

	Six Months Ended June 30					
	2015			2014		
($ thousands)	Canada	U.S.	Total	Canada	U.S.	Total
Exploration and development	$ 28,962	$ 224,477	$ 253,439	$ 252,374	$ 68,967	$ 321,341
Acquisitions, net of divestitures[1]	2,821	(101)	2,720	8,737	2,912,781	2,921,518
Total oil and natural gas capital expenditures	$ 31,783	$ 224,376	$ 256,159	$ 261,111	$2,981,748	$3,242,859

(1) Includes divestiture-related expenses.

During the three months ended June 30, 2015, exploration and development expenditures were $106.0 million, $42.9 million lower than the same period in 2014. The reduction includes a $90.1 million, or 92%, decrease in Canada compared to the second quarter of 2014. In the U.S., the increase in capital expenditures compared to last year reflects the acquisition of Eagle Ford. The second quarter Eagle Ford capital expenditures are $28.1 million lower than the $126.2 million spent during the first quarter of 2015 as 2.8 fewer net wells were drilled in the second quarter in response to the declining commodity prices. In the second quarter of 2015, we drilled 15.2 net wells (2.0 in Canada and 13.2 in the Eagle Ford) compared to 28.3 net wells (23.2 in Canada, 2.9 in the Eagle Ford and 2.2 in North Dakota) for the same period in 2014.

During the six months ended June 30, 2015, exploration and development expenditures were $253.4 million, $67.9 million lower than the same period in 2014. The reduction is comprised of decreases of $223.4 million, or 89%, in Canada and $42.9 million in North Dakota, partially offset by an increase of $198.4 million related to our Eagle Ford assets. In the first six months of 2015, we drilled 40.2 net wells (11.1 in Canada and 29.1 in the Eagle Ford) compared to 147.4 net wells (139.8 in Canada, 2.9 in the Eagle Ford and 4.7 in North Dakota) for the same period in 2014.

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 DRIP) divided by funds from operations. Baytex considers these to be key measures of performance as they demonstrate our 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 June 30		Six Months Ended June 30	
($ thousands except for %)	2015	2014	2015	2014
Cash flow from operating activities	$ 166,608	$ 152,087	$ 376,098	$ 273,696
Change in non-cash working capital	13,002	25,960	(13,298)	81,938
Asset retirement expenditures	3,160	2,992	7,606	6,888
Financing costs	(26,772)	(17,597)	(56,182)	(30,186)
Accretion on asset retirement obligations	1,548	1,779	3,166	3,520
Accretion on long-term debt	503	281	880	456
Funds from operations	$ 158,049	$ 165,502	$ 318,270	$ 336,312
Dividends declared	$ 61,773	$ 95,467	$ 112,423	$ 178,724
Reinvested dividends	(23,865)	(20,070)	(33,048)	(39,886)
Cash dividends declared (net of DRIP)	$ 37,908	$ 75,397	$ 79,375	$ 138,838
Payout ratio	39%	58%	35%	53%
Payout ratio (net of DRIP)	24%	46%	25%	41%

Baytex does not deduct capital expenditures when calculating the payout ratio. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, we may be required to reduce or eliminate dividends on our common shares in order to fund capital expenditures. There can be no certainty that we will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $37.9 million and $79.4 million for the three and six months ended June 30, 2015, respectively, were funded by funds from operations of $158.0 million and $318.3 million, respectively.

On June 15, 2015, we amended our dividend reinvestment plan to add a second reinvestment option, the Premium Dividend™ Component. The amended plan provides eligible shareholders of Baytex with two dividend reinvestment options: (i) dividends can be reinvested in new shares of Baytex issued at a 3% discount to the average market price (unchanged from previous plan) (the "Dividend Reinvestment Component"), or (ii) dividends can be reinvested in new shares of Baytex at a 3% discount to the average market price, with the new shares being exchanged for a cash payment equal to 101% of the reinvested dividend amount.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

We regularly review our liquidity sources as well as our exposure to counterparties and believe that our capital resources will be sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations, augmented by funds from our risk management program and our existing undrawn credit facilities, will provide sufficient liquidity to sustain our operations, dividends and planned capital expenditures. The timing of most of the capital expenditures are discretionary and there are no material long-term capital expenditure commitments. The dividend level is also discretionary, and we have the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes. Further, we believe that our counterparties have the financial capacity 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.

The current market environment, highlighted by unusually low commodity prices, has negative implications to our internally generated funds from operations. We have taken steps to protect our liquidity, including reducing the monthly dividend on our common shares from $0.24 per share to $0.10 per share effective December 2014, reducing our 2015 capital program by approximately 40% from our initial program and adding the Premium Dividend™ Component to the DRIP. We have also received relaxation of certain financial covenants applicable to our credit facilities. On April 2, 2015, we closed an equity financing whereby we issued 36,455,000 common shares at a price of $17.35 per share for aggregate gross proceeds of approximately $632.5 million. The net proceeds, after issuance costs, of approximately $606.0 million were utilized to pay down a portion of our credit facilities.

If the current commodity price environment continues, or if prices decline further, we may need to make additional changes to our capital program and/or the level of our dividend. A sustained low price environment could lead to a default of certain financial covenants, which could impact our ability to borrow under existing credit facilities or obtain new financing. It could also restrict our ability to pay dividends or sell assets and may result in our debt becoming immediately due and payable. Should our internally generated funds from operations be insufficient to fund the capital expenditures required to maintain operations, we may draw the maximum funds available under our current credit facilities or we may consider seeking additional capital in the form of debt or equity; however, there is no certainty that any of the additional sources of capital would be available when required.

The following table summarizes our total monetary debt at June 30, 2015 and December 31, 2014.

($ thousands)	June 30, 2015	December 31, 2014
Bank loan[1]	$ 192,255	$ 663,312
Long-term debt[1]	1,493,013	1,418,685
Working capital deficiency[2][3]	137,243	210,409
Total monetary debt	$ 1,822,511	$ 2,292,406

(1) Principal amount of instruments.

(2) Working capital is current assets less current liabilities (excluding non-cash items such as unrealized gains or losses on financial derivatives).

(3) In the oil and gas industry, it is not unusual to have a working capital deficiency as accounts receivable arising from sales of production are usually settled within one or two months but accounts payable related to capital and operating expenditures are usually settled over a longer time span (often two to four months) due to vendor billing cycles and internal approval processes.

At June 30, 2015, total monetary debt was $1,822.5 million, as compared to $2,292.4 million at December 31, 2014, with the decrease being primarily due to the application of $606 million from the equity financing to the bank loan, offset by the revaluation of our U.S. dollar denominated monetary debt and additional draws on the bank loan to fund the capital expenditure program. The impact of the movement in exchange rates since December 2014 has resulted in an aggregate increase in bank loan and long-term debt of $89.6 million.

Bank Loan

Baytex has established revolving extendible unsecured credit facilities with its bank lending syndicate comprised of a $50 million operating loan and a $950 million syndicated loan for Baytex and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the “Revolving Facilities”). On May 25, 2015, Baytex reached an agreement with its lending syndicate to extend the revolving period under the Revolving Facilities to June 4, 2019 (from June 4, 2018).

The Revolving Facilities contain standard commercial covenants for facilities of this nature and do not require any mandatory principal payments prior to maturity on June 4, 2019. Baytex may request an extension under the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year term at any time). At June 30, 2015, $192.3 million was drawn on the Revolving Facilities leaving approximately $1,046.0 million in undrawn credit capacity. Copies of the agreements relating to the Revolving Facilities are accessible on the SEDAR website at www.sedar.com (filed under the categories “Other material contracts” on June 11, 2014, September 9, 2014 and February 24, 2015 and “Material contracts – Credit agreements” on May 27, 2015).

Long-term Debt

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the “2021 Notes”) and US$400 million of 5.625% notes due June 1, 2024 (the “2024 Notes”). The 2021 Notes and the 2024 Notes pay interest semi-annually and are redeemable at the Company’s option, in whole or in part, commencing on June 1, 2017 (in the case of the 2021 Notes) and June 1, 2019 (in the case of the 2024 Notes) at specified redemption prices.

Pursuant to the acquisition of Aurora Oil & Gas Limited ("Aurora") on June 11, 2014, we assumed all of Aurora's existing senior unsecured notes and then purchased and cancelled approximately 98% of the outstanding notes. On February 27, 2015, we redeemed one tranche of the remaining Aurora notes at a price of US$8.3 million plus accrued interest. The remaining Aurora notes (US$6.4 million principal amount) are redeemable at our option, in whole or in part, commencing on April 1, 2016 at specified redemption prices.

On July 19, 2012, we issued $300 million principal amount of senior unsecured notes bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. These notes are redeemable at our option, in whole or in part, commencing on July 19, 2017 at specified redemption prices.

On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. These notes are redeemable at our option, in whole or in part, commencing on February 17, 2016 at specified redemption prices.

Covenants

The following table lists the financial covenants under the Revolving Facilities and the senior unsecured notes, and the compliance therewith as at June 30, 2015.

Covenant Description		Position as at June 30, 2015
Revolving Facilities	**Maximum Ratio**	
Senior debt to Capitalization(1)(2)	0.65:1.00	0.36:1.00
Senior debt to Bank EBITDA(1)(5)	4.75:1.00	1.72:1.00
Total debt to Bank EBITDA(3)(5)	4.75:1.00	1.72:1.00
Senior Unsecured Notes	**Minimum Ratio**	
Fixed charge coverage(4)	2:50:1.00	8.51:1.00

(1) *"Senior debt" is defined as the sum of the principal amount of our bank loan and principal amount of long-term debt.*

(2) *"Capitalization" is defined as the sum of the principal amount of our bank loan, principal amount of long-term debt and shareholders' equity.*

(3) *"Total debt" is defined as the sum of the principal amount of our bank loan, principal amount of long-term debt, and certain other liabilities identified in the credit agreement.*

(4) *Fixed charge coverage is computed as the ratio of financing costs to trailing twelve month adjusted income, as defined in the note indentures. Adjusted income for the trailing twelve months ended June 30, 2015 was $986.8 million.*

(5) *Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income for financing costs, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, amortization, impairment, exploration expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation), and acquisition and disposition activity and is calculated based on a trailing twelve month basis.*

On February 20, 2015, we reached an agreement with our lending syndicate to amend the financial covenants contained in the Revolving Facilities as follows: a) the maximum Senior Debt to capitalization ratio will be 0.65:1.00 for the period December 31, 2014 up to and including December 31, 2016, and 0.55:1.00 thereafter; b) the maximum Senior Debt to Bank EBITDA ratio will be 4.75:1.00 for the period December 31, 2014 up to and including June 30, 2016, 4.50:1.00 for the period July 1, 2016 up to and including December 31, 2016, and 3.50:1.00 thereafter; and c) the maximum Total Debt to Bank EBITDA will be 4.75:1.00 for the period December 31, 2014 up to and including December 31, 2016, and 4.00:1.00 thereafter. If we exceed or breach any of the covenants under the Revolving Facilities or our senior unsecured notes, we may be required to repay, refinance or renegotiate the loan terms and may be restricted from paying dividends to our shareholders.

Financial Instruments

As part of our normal operations, we are exposed to a number of financial risks, including liquidity risk, credit risk and market risk. Liquidity risk is the risk that we will encounter difficulty in meeting obligations associated with financial liabilities. We manage liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default, resulting in us incurring a loss. Credit risk is managed by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. 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 partially mitigated through a series of derivative contracts intended to reduce some of the volatility of our funds from operations.

A summary of the risk management contracts in place as at June 30, 2015 and the accounting treatment thereof is disclosed in note 17 to the consolidated financial statements.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. The rights and terms of preferred shares are determined upon issuance. As at July 24, 2015, we had 207,206,329 common shares and no preferred shares issued and outstanding. During the six months ended June 30, 2015, shares were issued through the equity financing, the DRIP and our share-based compensation programs.

Contractual Obligations

We have 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 in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of June 30, 2015 and the expected timing for funding 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	**$ 261,382**	$ 261,382	$ –	$ –	$ –
Dividends payable to shareholders	**20,619**	20,619	–	–	–
Bank loan(1)(2)	**192,255**	–	–	192,255	–
Long-term debt(2)	**1,493,013**	–	–	7,983	1,485,030
Operating leases	**53,631**	7,861	16,065	15,970	13,735
Processing agreements	**58,633**	10,469	13,301	9,043	25,820
Transportation agreements	**73,511**	12,752	22,176	21,064	17,519
Total	**$ 2,153,044**	$ 313,083	$ 51,542	$ 246,315	$ 1,542,104

(1) The bank loan is a covenant-based loan with a revolving period that is extendible annually for up to a four-year term. Unless extended, the revolving period will end on June 4, 2019, with all amounts to be re-paid on such date.
(2) Principal amount of instruments.

We also have 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.

QUARTERLY FINANCIAL INFORMATION

($ thousands, except per common share amounts)	2015		2014				2013	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Gross revenues	**345,432**	285,615	472,394	634,415	476,404	385,809	330,712	422,791
Net income (loss)	**(26,955)**	(175,916)	(361,816)	144,369	36,799	47,841	31,173	87,331
Per common share – basic	**(0.13)**	(1.04)	(2.16)	0.87	0.27	0.38	0.26	0.70
Per common share – diluted	**(0.13)**	(1.04)	(2.16)	0.86	0.27	0.38	0.25	0.70

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 but not limited to: our business strategies, plans and objectives; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; the proposed reassessment of our tax filings by the CRA to deny non-capital loss deductions for taxation years 2011 through 2013, including our intention to file tax returns for subsequent taxation years in a manner consistent with previous filings, our view of our tax filing position and our intention to defend the proposed reassessments if issued by the CRA; 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; the existence, operation and strategy of our risk management program, including our intent of partially mitigating some of the volatility in our funds from operations through a series of derivative contracts; and our objective to fund our capital expenditures and cash dividends on our common shares with funds from operations and existing credit capacity. 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: our ability to execute and realize on the anticipated benefits of the acquisition of Aurora; 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 for our operating activities; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural *gas prices; substantial or extended declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; uncertainties in the capital markets that may restrict the availability of or increase the cost of capital or of borrowing; refinancing risk for existing debt and the risk of failing to comply with covenants in existing debt agreements; risks associated with properties operated by third parties, specifically with respect to a substantially majority of our Eagle Ford assets; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; our inability to fully insure against all hazards associated with acquiring, developing and exploring for oil and natural gas; business risks; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; 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 our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2014, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.*

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

™ denotes trademark of Canaccord Genuity Corp.

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(thousands of Canadian dollars) (unaudited)*	June 30, 2015	December 31, 2014
ASSETS		
Current assets		
Cash	$ 274	$ 1,142
Trade and other receivables	144,032	203,259
Crude oil inventory	452	262
Financial derivatives	55,684	220,146
	200,442	424,809
Non-current assets		
Financial derivatives	6,893	498
Exploration and evaluation assets (note 4)	571,621	542,040
Oil and gas properties (note 5)	5,119,167	4,983,916
Other plant and equipment	27,787	34,268
Goodwill (note 6)	263,507	245,065
	$ 6,189,417	$ 6,230,596
LIABILITIES		
Current liabilities		
Trade and other payables	$ 261,382	$ 398,261
Dividends payable to shareholders	20,619	16,811
Financial derivatives	26,683	54,839
	308,684	469,911
Non-current liabilities		
Bank loan (note 7)	188,038	663,312
Long-term debt (note 8)	1,472,666	1,399,032
Asset retirement obligations (note 9)	283,550	286,032
Deferred income tax liability	890,854	905,532
	3,143,792	3,723,819
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 10)	4,234,873	3,580,825
Contributed surplus	31,908	31,067
Accumulated other comprehensive income	398,828	199,575
Deficit	(1,619,984)	(1,304,690)
	3,045,625	2,506,777
	$ 6,189,417	$ 6,230,596

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

(thousands of Canadian dollars, except per common share amounts) (unaudited)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014
Revenues, net of royalties (note 14)	$ 267,546	$ 364,122	$ 496,454	$ 675,051
Expenses				
Production and operating	82,080	76,496	169,835	145,331
Transportation and blending	23,390	38,584	49,012	83,487
Exploration and evaluation (note 4)	2,195	3,898	4,546	14,508
Depletion and depreciation	161,476	99,591	335,603	188,184
General and administrative	15,557	14,309	32,612	26,208
Acquisition-related costs	–	36,973	–	36,973
Share-based compensation (note 11)	8,229	8,232	16,233	16,087
Financing costs (note 15)	26,772	17,597	56,182	30,186
Financial derivatives loss (gain) (note 17)	1,667	49,123	(11,995)	42,045
Foreign exchange loss (gain) (note 16)	(13,975)	(18,455)	83,080	(13,937)
Divestiture of oil and gas properties (gain) loss	(24)	(18,741)	1,830	(18,741)
	307,367	307,607	736,938	550,331
Net income (loss) before income taxes	(39,821)	56,515	(240,484)	124,720
Income tax (recovery) expense (note 13)				
Current income tax (recovery) expense	(553)	–	16,382	–
Deferred income tax (recovery) expense	(12,313)	19,716	(53,995)	40,080
	(12,866)	19,716	(37,613)	40,080
Net income (loss) attributable to shareholders	$ (26,955)	$ 36,799	$ (202,871)	$ 84,640
Other comprehensive income				
Foreign currency translation adjustment	(41,665)	(57,332)	199,253	(47,125)
Comprehensive income (loss)	$ (68,620)	$ (20,533)	$ (3,618)	$ 37,515
Net income (loss) per common share (note 12)				
Basic	$ (0.13)	$ 0.27	$ (1.08)	$ 0.65
Diluted	$ (0.13)	$ 0.27	$ (1.08)	$ 0.64
Weighted average common shares (note 12)				
Basic	205,896	135,620	187,106	130,806
Diluted	205,896	137,158	187,106	132,332

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars) *(unaudited)*	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2013	$ 2,004,203	$ 53,081	$ 1,484	$ (776,283)	**$ 1,282,485**
Dividends to shareholders	–	–	–	(178,724)	**(178,724)**
Exercise of share rights	10,348	(5,626)	–	–	**4,722**
Vesting of share awards	16,932	(16,932)	–	–	**–**
Share-based compensation	–	16,087	–	–	**16,087**
Issued for cash	1,495,044	–	–	–	**1,495,044**
Issuance costs, net of tax	(78,468)	–	–	–	**(78,468)**
Issued pursuant to dividend reinvestment plan	38,970	–	–	–	**38,970**
Comprehensive income for the period	–	–	(47,125)	84,640	**37,515**
Balance at June 30, 2014	$ 3,487,029	$ 46,610	$ (45,641)	$ (870,367)	**$ 2,617,631**
Balance at December 31, 2014	3,580,825	31,067	199,575	(1,304,690)	**2,506,777**
Dividends to shareholders	–	–	–	(112,423)	**(112,423)**
Vesting of share awards	15,392	(15,392)	–	–	**–**
Share-based compensation	–	16,233	–	–	**16,233**
Issued for cash	632,494	–	–	–	**632,494**
Issuance costs, net of tax	(19,301)	–	–	–	**(19,301)**
Issued pursuant to dividend reinvestment plan	25,463	–	–	–	**25,463**
Comprehensive income (loss) for the period	–	–	199,253	(202,871)	**(3,618)**
Balance at June 30, 2015	$ 4,234,873	$ 31,908	$ 398,828	$ (1,619,984)	**$ 3,045,625**

See accompanying notes to the condensed interim consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended June 30		Six Months Ended June 30	
(thousands of Canadian dollars) (unaudited)	**2015**	2014	**2015**	2014
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income (loss) for the period	**$ (26,955)**	$ 36,799	**$ (202,871)**	$ 84,640
Adjustments for:				
Share-based compensation (note 11)	**8,229**	8,232	**16,233**	16,087
Unrealized foreign exchange (gain) loss (note 16)	**(18,349)**	(21,379)	**82,967**	(14,923)
Exploration and evaluation	**2,195**	3,898	**4,546**	14,508
Depletion and depreciation	**161,476**	99,591	**335,603**	188,184
Unrealized financial derivatives loss (note 17)	**41,739**	35,326	**129,911**	22,501
Divestitures of oil and gas properties (gain) loss	**(24)**	(18,741)	**1,830**	(18,741)
Deferred income tax (recovery) expense	**(12,313)**	19,716	**(53,995)**	40,080
Financing costs (note 15)	**26,772**	17,597	**56,182**	30,186
Change in non-cash working capital	**(13,002)**	(25,960)	**13,298**	(81,938)
Asset retirement obligations settled (note 9)	**(3,160)**	(2,992)	**(7,606)**	(6,888)
	166,608	152,087	**376,098**	273,696
Financing activities				
Payment of dividends	**(43,136)**	(67,251)	**(83,151)**	(127,637)
Increase (decrease) in secured bank loan	**–**	(300,564)	**–**	(223,371)
(Decrease) Increase in unsecured bank loan	**(581,653)**	805,258	**(482,582)**	805,258
Net proceeds from issuance of long-term debt	**–**	849,944	**–**	894,944
Redemption of long-term debt	**–**	(793,099)	**(10,372)**	(793,099)
Issuance of common shares related to share rights (note 10)	**–**	2,388	**–**	4,722
Issuance of common shares, net of issue costs (note 10)	**606,095**	1,401,317	**606,095**	1,401,317
Interest paid	**(28,760)**	(12,149)	**(50,350)**	(29,460)
	(47,454)	1,885,844	**(20,360)**	1,932,674
Investing activities				
Additions to exploration and evaluation assets (note 4)	**(1,655)**	(1,828)	**(3,698)**	(9,148)
Additions to oil and gas properties (note 5)	**(104,355)**	(147,088)	**(249,741)**	(312,193)
Property acquisitions, net of divestitures	**(1,170)**	(9,106)	**(2,720)**	(9,779)
Corporate acquisition	**–**	(1,866,307)	**–**	(1,866,307)
Current income tax expense on divestiture	**–**	–	**(8,181)**	–
Additions to other plant and equipment, net of disposals	**336**	(4,104)	**4,706**	(4,861)
Change in non-cash working capital	**(16,848)**	6,677	**(97,807)**	40,208
	(123,692)	(2,021,756)	**(357,441)**	(2,162,080)
Impact of foreign currency translation on cash balances	**(150)**	(363)	**835**	494
Change in cash	**(4,688)**	15,812	**(868)**	44,784
Cash, beginning of period	**4,962**	2,340	**1,142**	18,368
Cash, end of period	**$ 274**	$ 18,152	**$ 274**	$ 63,152

See accompanying notes to the condensed interim consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

As at June 30, 2015 and December 31, 2014 and for the three and six months ended June 30, 2015 and 2014
(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 ("TSX") 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 34, Interim Financial Reporting, as issued by the International Accounting Standards Board (the "IASB"). 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, 2014. The Company's accounting policies are unchanged compared to December 31, 2014. The use of estimates and judgments is also consistent with the December 31, 2014 financial statements.

The consolidated financial statements were approved by the Board of Directors of Baytex on July 29, 2015.

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. Prior period financial statement amounts have been reclassified to conform with current period presentation.

3. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the Company's geographic locations.

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada.
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the state of Texas, USA and, for the comparative period, the state of North Dakota, USA. The Texas assets were acquired on June 11, 2014. The North Dakota assets were sold on September 24, 2014.
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended June 30	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Revenues, net of royalties	**$ 149,188**	$ 310,804	**$ 118,358**	$ 53,318	**$ –**	$ –	**$ 267,546**	$ 364,122
Expenses								
Production and operating	**55,341**	68,623	**26,739**	7,873	**–**	–	**82,080**	76,496
Transportation and blending	**23,390**	38,584	**–**	–	**–**	–	**23,390**	38,584
Exploration and evaluation	**2,195**	1,008	**–**	2,890	**–**	–	**2,195**	3,898
Depletion and depreciation	**67,711**	77,011	**92,820**	21,856	**945**	724	**161,476**	99,591
General and administrative	**–**	–	**–**	–	**15,557**	14,309	**15,557**	14,309
Acquisition-related costs	**–**	–	**–**	–	**–**	36,973	**–**	36,973
Share-based compensation	**–**	–	**–**	–	**8,229**	8,232	**8,229**	8,232
Financing costs	**–**	–	**–**	–	**26,772**	17,597	**26,772**	17,597
Financial derivatives loss	**–**	–	**–**	–	**1,667**	49,123	**1,667**	49,123
Foreign exchange (gain)	**–**	–	**–**	–	**(13,975)**	(18,455)	**(13,975)**	(18,455)
Divestiture of oil and gas properties (gain)	**–**	–	**(24)**	–	**–**	(18,741)	**(24)**	(18,741)
	148,637	185,226	**119,535**	32,619	**39,195**	89,762	**307,367**	307,607
Net income (loss) before income taxes	**551**	125,578	**(1,177)**	20,699	**(39,195)**	(89,762)	**(39,821)**	56,515
Income tax expense								
Current income tax (recovery) expense	**(2,410)**	–	**1,857**	–	**–**	–	**(553)**	–
Deferred income tax (recovery) expense	**28,676**	36,061	**(18,261)**	6,441	**(22,728)**	(22,786)	**(12,313)**	19,716
	26,266	36,061	**(16,404)**	6,441	**(22,728)**	(22,786)	**(12,866)**	19,716
Net income (loss)	**$ (25,715)**	$ 89,517	**$ 15,227**	$ 14,258	**$ (16,467)**	$ (66,976)	**$ (26,955)**	$ 36,799
Total oil and natural gas capital expenditures[1]	**$ 9,100**	$ 106,542	**$ 98,080**	$2,963,219	**$ –**	$ –	**$ 107,180**	$3,069,761

(1) *Includes acquisitions and divestitures.*

	Canada		U.S.		Corporate		Consolidated	
Six Months Ended June 30	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Revenues, net of royalties	**$ 270,413**	$ 604,770	**$ 226,041**	$ 70,281	**$ –**	$ –	**$ 496,454**	$ 675,051
Expenses								
Production and operating	**115,915**	132,556	**53,920**	12,775	**–**	–	**169,835**	145,331
Transportation and blending	**49,012**	83,487	**–**	–	**–**	–	**49,012**	83,487
Exploration and evaluation	**4,546**	8,073	**–**	6,435	**–**	–	**4,546**	14,508
Depletion and depreciation	**142,828**	158,457	**191,204**	28,466	**1,571**	1,261	**335,603**	188,184
General and administrative	**–**	–	**–**	–	**32,612**	26,208	**32,612**	26,208
Acquisition-related costs	**–**		**–**		**–**	36,973	**–**	36,973
Share-based compensation	**–**	–	**–**	–	**16,233**	16,087	**16,233**	16,087
Financing costs	**–**	–	**–**	–	**56,182**	30,186	**56,182**	30,186
Financial derivatives (gain) loss	**–**	–	**–**	–	**(11,995)**	42,045	**(11,995)**	42,045
Foreign exchange (gain) loss	**–**	–	**–**	–	**83,080**	(13,937)	**83,080**	(13,937)
Divestiture of oil and gas properties loss (gain)	**2,074**	–	**(244)**	–	**–**	(18,741)	**1,830**	(18,741)
	314,375	382,573	**244,880**	47,676	**177,683**	120,082	**736,938**	550,331
Net income (loss) before income taxes	**(43,962)**	222,197	**(18,839)**	22,605	**(177,683)**	(120,082)	**(240,484)**	124,720
Income tax expense								
Current income tax expense	**14,525**	–	**1,857**	–	**–**	–	**16,382**	–
Deferred income tax (recovery) expense	**(96,799)**	486	**(18,261)**	6,471	**61,065**	33,123	**(53,995)**	40,080
	(82,274)	486	**(16,404)**	6,471	**61,065**	33,123	**(37,613)**	40,080
Net income (loss)	**$ 38,312**	$ 221,711	**$ (2,435)**	$ 16,134	**$ (238,748)**	$ (153,205)	**$ (202,871)**	$ 84,640
Total oil and natural gas capital expenditures[(1)]	**$ 31,783**	$ 261,111	**$ 224,376**	$2,981,748	**$ –**	$ –	**$ 256,159**	$3,242,859

(1) Includes acquisitions and divestitures.

As at	**June 30, 2015**	December 31, 2014
Canadian assets	**$ 2,253,045**	$ 2,398,241
U.S. assets	**3,861,379**	3,598,192
Corporate assets	**74,993**	234,163
Total consolidated assets	**$ 6,189,417**	$ 6,230,596

4. EXPLORATION AND EVALUATION ASSETS

Cost	
As at December 31, 2013	**$ 162,987**
Capital expenditures	15,824
Corporate acquisition	391,127
Property acquisition	12,489
Exploration and evaluation expense	(17,743)
Transfer to oil and gas properties	(10,443)
Divestitures	(40,306)
Foreign currency translation	28,105
As at December 31, 2014	**$ 542,040**
Capital expenditures	3,712
Exploration and evaluation expense	(4,546)
Transfer to oil and gas properties	(1,006)
Foreign currency translation	31,421
As at June 30, 2015	**$ 571,621**

5. OIL AND GAS PROPERTIES

Cost	
As at December 31, 2013	**$ 3,223,768**
Capital expenditures	750,247
Corporate acquisition	2,520,612
Property acquisitions	85,600
Transferred from exploration and evaluation assets	10,443
Change in asset retirement obligations	69,844
Divestitures	(426,477)
Foreign currency translation	197,723
As at December 31, 2014	**6,431,760**
Capital expenditures	249,741
Property acquisitions	2,216
Transferred from exploration and evaluation assets	1,006
Change in asset retirement obligations	489
Divestitures	(1,339)
Foreign currency translation	232,919
As at June 30, 2015	**$ 6,916,792**

Accumulated depletion	
As at December 31, 2013	**$ 1,000,982**
Depletion for the period	532,825
Divestitures	(96,916)
Foreign currency translation	10,953
As at December 31, 2014	**$ 1,447,844**
Depletion for the period	333,749
Foreign currency translation	16,032
As at June 30, 2015	**$ 1,797,625**

Carrying value	
As at December 31, 2014	**$ 4,983,916**
As at June 30, 2015	**$ 5,119,167**

6. GOODWILL

As at December 31, 2013	**$ 37,755**
Acquired goodwill	615,338
Impairment	(449,590)
Foreign currency translation	41,562
As at December 31, 2014	**$ 245,065**
Foreign currency translation	18,442
As at June 30, 2015	**$ 263,507**

7. BANK LOAN

	June 30, 2015	December 31, 2014
Bank loan	**$ 188,038**	$ 663,312

Baytex has established revolving extendible unsecured credit facilities with its bank lending syndicate that include a $50 million operating loan, a $950 million syndicated loan for Baytex and a US$200 million syndicated loan for its wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities"). On May 25, 2015, Baytex reached an agreement with its lending syndicate to extend the revolving period under the Revolving Facilities to June 4, 2019 (from June 4, 2018).

The Revolving Facilities contain standard commercial covenants for facilities of this nature and are guaranteed by Baytex and its subsidiaries. In the event that Baytex exceeds or breaches any of the covenants under the Revolving Facilities, its ability to pay dividends to its shareholders, borrow funds or increase the facilities may be restricted. Baytex is in compliance with all covenants at June 30, 2015.

The weighted average interest rate on the bank loan was 4.02% for the three months ended June 30, 2015 (three months ended June 30, 2014 – 3.73%) and 3.09% for the six months ended June 30, 2015 (six months ended June 30, 2014 – 3.92%).

8. LONG-TERM DEBT

	June 30, 2015	December 31, 2014
9.875% notes (US$7,900 – principal) due February 15, 2017	**$ –**	$ 9,737
7.500% notes (US$6,400 – principal) due April 1, 2020	**8,715**	8,167
6.750% notes (US$150,000 – principal) due February 17, 2021	**185,295**	172,207
5.125% notes (US$400,000 – principal) due June 1, 2021	**493,420**	458,554
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**295,123**	294,859
5.625% notes (US$400,000 – principal) due June 1, 2024	**490,113**	455,508
Total long-term debt	**$ 1,472,666**	$ 1,399,032

On February 27, 2015, the Company redeemed all of the outstanding 9.875% notes due February 15, 2017 for US$8.3 million plus accrued interest.

Each of the outstanding notes are redeemable in accordance with the redemption provisions contained in the respective indenture agreements. A financial derivative gain of $3.4 million and $5.3 million for the three and six months ended June 30, 2015, respectively (three and six months ended June 30, 2014 – $12.1 million gain) has been recorded. As at June 30, 2015, a $5.7 million asset has been included in financial derivatives (December 31, 2014 – $0.5 million asset) representing the aggregate fair value of the redemption features on all notes.

9. ASSET RETIREMENT OBLIGATIONS

	June 30, 2015	December 31, 2014
Balance, beginning of period	$ 286,032	$ 221,628
Liabilities incurred	2,042	18,516
Liabilities settled	(7,606)	(14,528)
Liabilities divested, net of acquisitions	(171)	(21,817)
Accretion	3,166	7,251
Change in estimate(1)	(1,382)	31,599
Changes in discount rates and inflation rates	–	42,763
Foreign currency translation	1,469	620
Balance, end of period	$ 283,550	$ 286,032

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

10. 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, 2015, 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, 2013	**125,392**	**$ 2,004,203**
Issued on exercise of share rights	683	11,298
Transfer from contributed surplus on exercise of share rights	–	14,369
Transfer from contributed surplus on vesting and conversion of share awards	842	35,108
Issued for cash	38,433	1,495,044
Issuance costs, net of tax	–	(78,468)
Issued pursuant to dividend reinvestment plan	2,757	99,271
Balance, December 31, 2014	**168,107**	**$ 3,580,825**
Transfer from contributed surplus on vesting and conversion of share awards	369	15,392
Issued for cash	36,455	632,494
Issuance costs, net of tax	–	(19,301)
Issued pursuant to dividend reinvestment plan	1,262	25,463
Balance, June 30, 2015	**206,193**	**$ 4,234,873**

On April 2, 2015, Baytex issued 36,455,000 common shares for aggregate gross and net proceeds of approximately $632.5 million and $606.0 million, respectively. Issuance costs of $26.4 million ($19.3 million, after tax) were incurred and recorded as a reduction to shareholders' capital.

The Company declared monthly dividends of $0.10 per common share for the six months ended June 30, 2015. During the three and six months ended June 30, 2015, total dividends of $61.8 million ($37.9 million net of dividend reinvestment) and $112.4 million ($79.4 million net of dividend reinvestment), respectively, were declared. During the three and six months ended June 30, 2014, total dividends of $95.5 million ($75.4 million net of dividend reinvestment) and $178.7 million ($138.8 million net of dividend reinvestment), respectively, were declared.

11. EQUITY-BASED PLANS

Share Award Incentive Plan

The Company recorded compensation expense related to the share awards of $8.2 million for the three months ended June 30, 2015 (three months ended June 30, 2014 – $8.2 million) and $16.2 million for the six months ended June 30, 2015 (six months ended June 30, 2014 – $16.1 million).

The estimated weighted average fair value for the share awards at the measurement date is $17.11 per award granted during the six months ended June 30, 2015 (six months ended June 30, 2014 – $40.36 per award).

The number of share awards outstanding is detailed below:

	Number of restricted awards *(000s)*	Number of performance awards *(000s)*	Total number of share awards *(000s)*
Balance, December 31, 2013	**723**	**580**	**1,303**
Granted	533	483	1,016
Vested and converted to common shares	(320)	(258)	(578)
Forfeited	(189)	(190)	(379)
Balance, December 31, 2014	**747**	**615**	**1,362**
Granted	595	487	1,083
Vested and converted to common shares	(146)	(117)	(263)
Forfeited	(48)	(33)	(82)
Balance, June 30, 2015	**1,148**	**952**	**2,100**

Share Rights Plan

All outstanding share rights are fully expensed and exercisable. As at June 30, 2015, there were 22,500 share rights outstanding with a weighted average exercise price of $24.71 per share right.

12. NET INCOME (LOSS) PER SHARE

	Three Months Ended June 30					
	2015			2014		
	Net loss	Common shares *(000s)*	Net loss per share	Net income	Common shares *(000s)*	Net income per share
Net income (loss) – basic	$ (26,955)	205,896	$ (0.13)	$ 36,799	135,620	$ 0.27
Dilutive effect of share awards	–	–	–	–	1,284	–
Dilutive effect of share rights	–	–	–	–	254	–
Net income (loss) – diluted	$ (26,955)	205,896	$ (0.13)	$ 36,799	137,158	$ 0.27

	Six Months Ended June 30					
	2015			2014		
	Net loss	Common shares *(000s)*	Net loss per share	Net income	Common shares *(000s)*	Net income per share
Net income (loss) – basic	$ (202,871)	187,106	$ (1.08)	$ 84,640	130,806	$ 0.65
Dilutive effect of share awards	–	–	–	–	1,266	–
Dilutive effect of share rights	–	–	–	–	260	–
Net income (loss) – diluted	$ (202,871)	187,106	$ (1.08)	$ 84,640	132,332	$ 0.64

The number of anti-dilutive share awards was 1.3 million for the three months ended June 30, 2015 (three months ended June 30, 2014 – nil) and 1.1 million for the six months ended June 30, 2015 (six months ended June 30, 2014 – nil).

13. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2015	2014
Net income (loss) before income taxes	$ (240,484)	$ 124,720
Expected income taxes at the statutory rate of 26.23%(1) (2014 – 25.47%)	(63,079)	31,766
Increase (decrease) in income taxes resulting from:		
Share-based compensation	4,258	4,097
Non-taxable portion of foreign exchange loss	10,877	–
Effect of change in income tax rates	10,984	–
Effect of rate adjustments for foreign jurisdictions	(23,296)	952
Effect of change in deferred tax benefit not recognized	22,620	–
Other	23	3,265
Income tax (recovery) expense	$ (37,613)	$ 40,080

(1) Expected income tax rate increased due to an increase in the corporate income tax rate in Alberta (from 10% to 12%), offset by a decrease in the Texas Franchise Tax rate (from 1.00% to 0.75%).

In 2014, the Canada Revenue Agency ("CRA") advised Baytex that it was proposing to reassess certain subsidiaries of Baytex to deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2013. Baytex has filed its 2014 income tax return and intends to file its future tax returns on the same basis as the 2011 through 2013 tax returns, cumulatively claiming $591 million of non-capital losses. The Company believes that it should be entitled to deduct the non-capital losses, that its tax filings to-date are correct, and has formally responded with a letter to the CRA indicating the same. At this time, the CRA has not issued a reply to Baytex's letter. The Company expects to continue to defend the position as filed.

14. REVENUES

	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Petroleum and natural gas revenues	$ 342,135	$ 474,901	$ 624,908	$ 859,323
Royalty expenses	(77,886)	(112,282)	(134,593)	(187,162)
Royalty income	668	1,088	1,278	2,475
Other income	2,629	415	4,861	415
Revenues, net of royalties	$ 267,546	$ 364,122	$ 496,454	$ 675,051

15. FINANCING COSTS

	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Bank loan and other	$ 3,345	$ 4,566	$ 8,763	$ 10,658
Long-term debt	21,879	11,252	44,253	16,008
Accretion on asset retirement obligations	1,548	1,779	3,166	3,520
Financing costs	$ 26,772	$ 17,597	$ 56,182	$ 30,186

16. SUPPLEMENTAL INFORMATION

Foreign Exchange

	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	**2015**	2014
Unrealized foreign exchange (gain) loss	**$ (18,349)**	$ (21,379)	**$ 82,967**	$ (14,923)
Realized foreign exchange loss	**4,374**	2,924	**113**	986
Foreign exchange (gain) loss	**$ (13,975)**	$ (18,455)	**$ 83,080**	$ (13,937)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

At June 30, 2015, the Company had in place the following currency derivative contracts relating to operations:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	July 2015 to December 2015	US$4.00 million	1.1075	(2)
Monthly average rate forward	July 2015 to December 2015	US$13.50 million	1.1011	(1)
Monthly range forward spot sale	July 2015 to December 2015	US$1.00 million	1.1000-1.1674	(1)(3)
Contingent monthly forward spot sale	July 2015 to December 2015	US$1.00 million	1.1674	(1)(4)

(1) Based on the weighted average contract rates (CAD/USD).

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

(3) Settlement at or below the lower end of the price collar results in settlement at the lower end of the price collar. Settlement above the lower end of the price collar results in settlement at the higher end of the price collar.

(4) Settlement required if settlement price is above the strike price; contract entered into simultaneously with monthly average range forward contract or monthly range forward spot sale.

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, 2015	December 31, 2014	**June 30, 2015**	December 31, 2014
U.S. dollar denominated	**US$118,821**	US$329,716	**US$1,196,120**	US$1,295,391

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, 2015, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	July 2015 to December 2015	6,000 bbl/d	US$85.65	WTI
Fixed – Sell	July 2015 to June 2016	2,000 bbl/d	US$62.50	WTI
Bought US$90.00/80.00 put spread	July 2015	5,032 bbl/d	WTI plus US$10.00/bbl(2)	WTI
Bought US$90.00/80.00 put spread	August 2015	4,903 bbl/d	WTI plus US$10.00/bbl(2)	WTI
Fixed – Sell	October 2015 to March 2016	1,000 bbl/d	US$65.33	WTI
Fixed – Sell	January 2016 to December 2016	5,000 bbl/d	US$63.79	WTI

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

(2) These premiums are in effect for WTI index averages of US$80.00 or less. As the WTI index climbs towards the upper put spread limit, the premium erodes to no value.

Natural Gas	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	July 2015 to December 2015	10,000 mmBtu/d	US$3.03	NYMEX
Fixed – Sell	July 2015 to December 2015	10,000 GJ/d	$2.85	AECO
Fixed – Sell	January 2016 to December 2016	5,000 mmBtu/d	US$3.25	NYMEX
Fixed – Sell	January 2016 to December 2016	5,000 GJ/d	$2.98	AECO

(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 consolidated statements of income (loss) and comprehensive income (loss):

	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	**2015**	2014
Realized financial derivatives (gain) loss	**$ (40,072)**	$ 13,797	**$ (141,906)**	$ 19,544
Unrealized financial derivatives loss – commodity	**45,158**	47,402	**135,191**	34,577
Unrealized financial derivatives gain – redemption feature on long-term debt	**(3,419)**	(12,076)	**(5,280)**	(12,076)
Financial derivatives loss (gain)	**$ 1,667**	$ 49,123	**$ (11,995)**	$ 42,045

Physical Delivery Contracts

At June 30, 2015, Baytex had committed to deliver the volumes of raw bitumen noted below to market on rail:

	Period	Term Volume
Raw bitumen	July 2015 to December 2015	2,000 bbl/d

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
DRIP	Dividend Reinvestment Plan
GAAP	Generally Accepted Accounting Principles
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLS	Louisiana Light Sweet
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

Raymond T. Chan
Chairman of the Board
Baytex Energy Corp.

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

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

Edward Chwyl(2)(3)(4)
Lead Independent Director
Baytex Energy Corp.
Independent Businessman

Naveen Dargan(1)(2)
Independent Businessman

R. E. T. (Rusty) Goepel(4)
Senior Vice President
Raymond James Ltd.

Gregory K. Melchin(1)
Independent Businessman

Mary Ellen Peters(1)(2)
Independent Businesswoman

Dale O. Shwed(3)
President & 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

HEAD OFFICE

Baytex Energy Corp.
Centennial Place, East Tower
2800, 520 – 3rd Avenue SW
Calgary, Alberta T2P 0R3
Toll-free: 1-800-524-5521
T: 587-952-3000
F: 587-952-3001

www.baytexenergy.com

BANKERS

Bank of Nova Scotia
Alberta Treasury Branches
Bank of America
Bank of Montreal
Barclays Bank plc
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
National Bank of Canada
Royal Bank of Canada
Société Générale
The Toronto-Dominion Bank
Union Bank
Wells Fargo Bank

OFFICERS

James L. Bowzer
President and Chief Executive Officer

Rodney D. Gray
Chief Financial Officer

Richard P. Ramsay
Chief Operating Officer

Geoffrey J. Darcy
Senior Vice President, Marketing

Brian G. Ector
Senior Vice President, Capital Markets
and Public Affairs

Kendall D. Arthur
Vice President,
Lloydminster Business Unit

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

Neal E. Halstead
Vice President, Finance and Controller

Cameron A. Hercus
Vice President, Corporate Development

Ryan M. Johnson
Vice President, Central Business Unit

Mark A. Montemurro
Vice President, Thermal Projects

Gregory A. Sawchenko
Vice President, Land

Michael L. Verm
Vice President, U.S. Business Unit

AUDITORS

Deloitte LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited
Ryder Scott Company L.P.

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE