FOR IMMEDIATE RELEASE – CALGARY, ALBERTA – August 11, 2011

BAYTEX ANNOUNCES SECOND QUARTER 2011 RESULTS

CALGARY, ALBERTA (August 11, 2011) - Baytex Energy Corp. (“Baytex”) (TSX, NYSE: BTE) is pleased to announce its operating and financial results for the three months and six months ended June 30, 2011 (in Canadian dollars unless otherwise denoted).

Summary of Q2

- Produced record quarterly production of 47,853 boe/d in Q2/2011 (an increase of 2% over Q1/2011 and 9% over Q2/2010);
- Generated funds from operations (“FFO”) of $138 million ($1.20 per basic share) in Q2/2011, the second highest level of quarterly FFO in the history of Baytex, and an increase of 26% over Q1/2011 and 29% over Q2/2010;
- Generated net income of $107 million ($0.92 per basic share) in Q2/2011;
- Continued cold development at our heavy oil resource play at Seal, with recently-drilled wells averaging 30-day peak production rates of approximately 680 bbl/d per well;
- Continued steam assisted gravity drainage ("SAGD") development at Kerrobert by drilling two new well pairs, the first of which is on production at initial rates of more than 1,000 bbl/d;
- Restructured our credit facilities as three-year covenant-based facilities and increased the amount of the facilities to $700 million (previously $650 million), of which $385 million remains undrawn at the end of Q2/2011;
- Maintained a cash payout ratio in Q2/2011 of 38% net of dividend reinvestment plan (“DRIP”) participation; and
- Subsequent to the end of the second quarter, closed a small natural gas-weighted acquisition in west-central Alberta to consolidate previously non-operated interests at attractive acquisition metrics.

	Three Months Ended			Six Months Ended	
	June 30, 2011	March 31, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
FINANCIAL					
(thousands of Canadian dollars, except per common share or unit amounts)					
Petroleum and natural gas sales	**336,899**	290,315	241,581	**627,214**	503,363
Funds from operations (1)	**138,233**	109,470	107,413	**247,703**	213,619
Per share or unit – basic	**1.20**	0.96	0.97	**2.15**	1.93
Per share or unit - diluted	**1.17**	0.93	0.94	**2.10**	1.87
Cash dividends or distributions declared(2)	**52,763**	52,002	46,761	**104,765**	95,903
Per share or unit	**0.60**	0.60	0.54	**1.20**	1.08
Net income	**106,863**	950	157,440	**107,813**	186,941
Per share or unit – basic	**0.92**	0.01	1.42	**0.94**	1.69
Per share or unit - diluted	**0.90**	0.01	1.38	**0.91**	1.64
Exploration and development	**108,453**	87,014	57,354	**195,467**	112,710
Property acquisitions	**(185)**	37,518	5,531	**37,333**	7,864
Corporate acquisition	**1,325**	117,346	40,314	**118,671**	40,314
Total oil and natural gas expenditures	**109,593**	241,878	103,199	**351,471**	160,888
Bank loan	**315,073**	298,591	341,919	**315,073**	341,919
Convertible debentures	**-**	-	5,864	**-**	5,864
Long-term debt	**294,645**	295,770	150,000	**294,645**	150,000
Working capital deficiency	**72,621**	73,709	62,283	**72,621**	62,283
Total monetary debt (3)	**682,339**	668,070	560,066	**682,339**	560,066

Notes:

(1) Funds from operations is a non-GAAP measure that represents cash generated from operating activities adjusted for finance costs, changes in non-cash operating working capital and other operating items. Baytex's funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund future dividends and capital investments. For a reconciliation of funds from operations to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three months and six months ended June 30, 2011.

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

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

	Three Months Ended			Six Months Ended	
	June 30, 2011	March 31, 2011	June 30, 2010	**June 30, 2011**	June 30, 2010
OPERATING					
Daily production					
Light oil and NGL (bbl/d)	**6,055**	6,606	6,443	**6,329**	6,551
Heavy oil (bbl/d)	**33,839**	31,792	28,263	**32,821**	27,773
Total oil (bbl/d)	**39,894**	38,398	34,706	**39,150**	34,324
Natural gas (mmcf/d)	**47.8**	51.0	56.4	**49.4**	56.7
Oil equivalent (boe/d @ 6:1) (1)	**47,853**	46,902	44,104	**47,380**	43,766
Average prices (before hedging)					
WTI oil (US$/bbl)	**102.56**	94.10	78.03	**98.33**	78.37
Edmonton par oil ($/bbl)	**102.63**	88.45	75.46	**95.57**	77.88
BTE light oil and NGL ($/bbl)	**89.11**	75.68	64.38	**82.14**	66.23
BTE heavy oil ($/bbl) (2)	**71.02**	59.89	57.59	**65.60**	59.78
BTE total oil and NGL ($/bbl)	**73.78**	62.57	58.84	**68.26**	61.01
BTE natural gas ($/mcf)	**4.36**	4.19	4.19	**4.27**	4.75
BTE oil equivalent ($/boe)	**65.84**	55.86	51.68	**60.89**	54.02
USD/CAD noon rate at period end	**1.0370**	1.0290	0.9429	**1.0370**	0.9429
USD/CAD average rate for period	**1.0334**	1.0142	0.9733	**1.0237**	0.9671
COMMON SHARE OR TRUST UNIT INFORMATION					
TSX					
Share or Unit price (Cdn$)					
High	**$ 58.76**	$ 56.95	$ 36.31	**$ 58.76**	$ 36.80
Low	**$ 47.59**	$ 46.00	$ 27.72	**$ 46.00**	$ 27.72
Close	**$ 52.72**	$ 56.69	$ 31.80	**$ 52.72**	$ 31.80
Volume traded (thousands)	**22,857**	34,198	28,441	**57,055**	50,889
NYSE					
Share or Unit price (US$)					
High	**$ 61.95**	$ 58.52	$ 36.23	**$ 61.95**	$ 36.23
Low	**$ 48.63**	$ 46.25	$ 25.64	**$ 46.25**	$ 25.64
Close	**$ 54.44**	$ 58.38	$ 29.95	**$ 54.44**	$ 29.95
Volume traded (thousands)	**9,851**	8,184	7,292	**18,035**	11,744
Common shares or trust units outstanding (thousands)	**116,004**	115,177	111,259	**116,004**	111,259

Notes:

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

(2) *Heavy oil wellhead prices are net of blending costs.*

Operations Review

Production averaged 47,853 boe/d during the second quarter of 2011, as compared to 44,104 boe/d in the second quarter of 2010 and 46,902 boe/d in the first quarter of 2011. Oil-equivalent production increased by 9% from the second quarter of 2010, with oil and natural gas liquids ("NGL") production 15% higher and natural gas production 15% lower. Oil equivalent production increased by 2% from the first quarter of 2011, with oil and NGL production 4% higher and natural gas production 6% lower. Second quarter production was negatively impacted by several weather factors, most notably extremely wet ground conditions in North Dakota, which reduced light oil deliveries.

Capital expenditures for exploration and development activities totaled $108.5 million for the second quarter of 2011. During the second quarter, Baytex participated in the drilling of 47 (38.0 net) wells, resulting in 44 (35.0 net) oil wells, two (2.0 net) service wells, and one (1.0 net) dry and abandoned well for a 98% (97% net) success rate. In our Lloydminster heavy oil area, we drilled 19 (16.8 net) oil wells, two (2.0 net) service wells, and one (1.0 net) dry and abandoned well. At Seal, we drilled eleven (11.0 net) horizontal cold production wells. In our light oil and gas areas in western Canada, we drilled six (4.5 net) oil wells. In North Dakota, we drilled eight (2.7 net) oil wells.

Heavy Oil

In the second quarter of 2011, heavy oil production averaged 33,839 bbl/d, an increase of 20% over the second quarter of 2010 and 6% over the first quarter of 2011. During the second quarter of 2011, we drilled 30 (27.8 net) oil wells, two (2.0 net) service wells, and one (1.0) dry and abandoned well on our heavy oil properties for a success rate of 97%.

Production from our Seal properties (excluding production from the properties acquired in the first quarter) averaged 12,850 bbl/d in the second quarter, an increase of 23% from the first quarter of 2011 and 44% from the second quarter of 2010. In addition to our legacy Seal properties, we produced 1,500 bbl/d from the Seal properties acquired earlier this year. In the second quarter of 2011, Seal drilling included eleven (11.0 net) cold horizontal producers, with 9 to 20 laterals per well. Our typical multi-lateral well design includes eight approximately 1,400 meter-long laterals, which are now usually augmented with several shorter laterals to drain the region around the intermediate casing point to the starting point of the 1,400 meter-long laterals. Nine of the wells drilled in the second quarter and three of the wells drilled in the first quarter established average 30-day peak production rates of approximately 680 bbl/d per well. For the remainder of 2011, we plan to drill approximately eleven additional multi-lateral cold horizontal wells at Seal, including four wells on the new lands acquired in the first quarter.

In our Cliffdale cyclic steam stimulation (CSS) project at Seal, we continued pilot well production operations following the third injection cycle. Oil production peaked at 435 bbl/d with second quarter oil rates averaging over 105 bbl/d. We project a steam-oil ratio of approximately 2.1 for the third cycle. Four CSS wells drilled in the first quarter continued cold production in the second quarter at rates of 20 to 25 bbl/d. Steam injection into these four wells is planned for the fourth quarter of 2011 following receipt of regulatory permits and completion of our steam facility expansion. To complete our first 10-well commercial module, we plan to drill an additional five horizontal CSS wells following receipt of regulatory approvals, which we expect to receive in the fourth quarter of 2011.

At our Kerrobert thermal project, the SAGD well pair which commenced production late in the third quarter of 2010 continues to operate at oil rates in excess of 1,000 bbl/d at a cumulative steam-oil ratio of approximately 2.7. Cumulative production from this well pair stands at 325,000 barrels after ten months of production. Two additional SAGD well pairs were drilled during the second quarter. Subsequent to the end of the second quarter, one of the new well pairs was put on production at initial rates in excess of 1,000 bbl/d. Start-up of the second new well pair is planned for later in the third quarter. We have identified at least nine further SAGD well pair locations at Kerrobert and plan to drill four additional stratigraphic test wells later this year to optimize the placement of these future well pairs. We are also performing engineering and procurement work to increase the steam plant capacity in 2012.

Light Oil & Natural Gas

During the second quarter of 2011, light oil, NGL and natural gas production averaged 14,014 boe/d, which was comprised of 6,055 bbl/d of light oil and NGL and 47.8 mmcf/d of natural gas. Compared to the second quarter of 2010, light oil and NGL production declined by 6% and natural gas production declined by 15%. Compared to the first quarter of 2011, light oil and NGL production declined by 8% and natural gas production declined by 6%. Light oil production declined primarily due to extremely wet ground conditions in North Dakota, which at one point during the second quarter required the shut-in of the majority of our production in the state. Light oil and natural gas production was also adversely impacted by forest fires and resulting pipeline curtailment in northern Alberta, and third party gas processing constraints in west-central Alberta. Production was restored for most of the shut-in wells late in the second quarter. A few wells in North Dakota will remain shut-in until alternate access routes are constructed. In the second quarter of 2011, we drilled 14 (7.2 net) oil wells in our light oil and natural gas areas.

In the second quarter of 2011, we drilled four (3.75 net) Viking multi-lateral wells in eastern Alberta. Two of the wells drilled in the second quarter and one well drilled in the first quarter established 30-day average peak rates of approximately 125 bbl/d per well. We plan to drill approximately 10 additional Viking light oil horizontal wells in 2011, the majority of which will be multi-lateral wells in Alberta.

Subsequent to the end of the second quarter, we closed the acquisition of predominantly natural gas assets located in the Brewster area of west-central Alberta. Prior to the acquisition, we had non-operated interests in most of these assets. As a result of the acquisition, we are now the operator of all of the acquired assets, which can readily be consolidated into our existing operations. The total consideration of the acquisition (net of adjustments) was $22.4 million, which was funded by drawing on our credit facilities. The purchase price is a multiple of approximately three times projected net operating income from the acquired properties for 2011. The acquired assets are expected to contribute 800 boe/d of production (80% natural gas) during the last four months of 2011. We estimate remaining proved plus probable reserves to be approximately 2.5 million boe. The acquired assets include 72,000 net acres of undeveloped land, a 64 kilometer gathering system and two compressor stations.

In our Bakken/Three Forks play in North Dakota, we participated in the drilling of eight (2.7 net) horizontal oil wells in the second quarter, three of which were Baytex-operated. Due to wet ground conditions, none of these wells, or any other wells that were drilled prior to the second quarter, were put on production for a sufficient length of time to establish 30-day peak production rates. With surface waters receding, completion and production activities are now returning to normal at most well locations. We expect to fracture-stimulate six wells during the third quarter and to operate a two-rig drilling program for the remainder of the year.

Capital and Production Guidance

Our Board of Directors has approved a $30 million increase to our exploration and development (“E&D”) capital budget, bringing our 2011 E&D capital budget to $355 million. The additional capital investment in the second half of 2011 will fund fuel gas and solution gas recovery infrastructure at Seal, initial drilling on the new lands acquired at Seal in the first quarter, stratigraphic test wells to advance SAGD development at Kerrobert, installation of a natural gas pipeline to bypass processing constraints and increase NGL recoveries in west-central Alberta, and increased drilling in North Dakota. The increased capital program facilitates our capital-efficient growth-and-income model by maintaining our key development programs at a consistent operating pace as we move towards 2012. Nonetheless, we will remain cognizant of commodity market conditions as we implement the increased capital program, and are prepared to make adjustments as necessary in the event of a more significant and protracted commodity downturn.

Prior to the incremental capital program and the natural gas acquisition in west-central Alberta, our production guidance for 2011 was 49,000 to 50,000 boe/d. The acquisition will add approximately 250 boe/d to our average production rate for 2011. Production impacts of the incremental capital program will begin late in 2011, and are estimated to add 250 boe/d to our average production rate for 2011. As a result of the combined effect of the acquisition and the incremental capital program, we are increasing our production guidance range for 2011 to 49,500 to 50,500 boe/d.

We now project that our production mix will be comprised of approximately 70% heavy oil, 14% light oil and NGL and 16% natural gas.

Financial Review

The financial statements for the second quarter of 2011 have been prepared in accordance with International Financial Reporting Standards (“IFRS”). Comparative periods in 2010 have been restated to conform to IFRS presentation. Reconciliations from IFRS to the previously reported financial results are shown in the notes to our financial statements. The adoption of IFRS did not have a material impact on the amounts reported as FFO.

We generated FFO of $138 million ($1.20 per basic share) in the second quarter of 2011, an increase of 29% compared to the second quarter of 2010, and an increase of 26% compared to the first quarter of 2011. Second quarter FFO is net of realized losses on our financial derivative program of $9.2 million. The increase in FFO relative to the first quarter of 2011 is primarily the result of increased production volumes and higher oil prices. Consistent with the calculation of FFO which we had historically presented under Canadian GAAP prior to the adoption of IFRS, FFO is presented net of financing costs, which totaled $12.8 million in the second quarter.

The average WTI price for the second quarter of 2011 was US$102.56/bbl, a 31% increase from the second quarter of 2010, and a 9% increase from the first quarter 2011. We received an average oil and NGL price of $73.78/bbl in the second quarter of 2011 (inclusive of our physical hedging gains), up from $58.84/bbl for the second quarter of 2010 and $62.57/bbl for the first quarter of 2011. We received an average natural gas price of $4.36/mcf in the second quarter of 2011, an increase of 4% from the second quarter of 2010 and the first quarter 2011.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("WCS") price differential to WTI, averaged 17.2% for the second quarter of 2011, as compared to 18.1% in the second quarter of 2010 and 24.3% in the first quarter of 2011. The export pipeline integrity issues that increased the WCS differential were largely resolved by the end of the first quarter, resulting in a narrower WCS differential in the second quarter of 2011. At present, WCS differentials for September 2011 are trading at approximately 16% of WTI. Looking forward, demand for Canadian heavy oil by U.S. refiners in the midcontinent region is expected to increase in late 2011 through 2013 with commissioning of heavy oil refining projects in the region.

During the second quarter of 2011, we generated net income of $106.9 million, as compared to $1.0 million in the first quarter of 2011. While operating results and higher commodity prices contributed meaningfully to the increase in net income, much of the volatility in quarterly earnings has resulted from the accounting for unrealized mark-to-market gains and losses from our WTI hedging program. In the second quarter of 2011, we recorded unrealized gains of $49.6 million, as compared to unrealized losses of $46.5 million in the first quarter of 2011.

On June 14, 2011, we reached agreement with our lending syndicate to amend our credit facilities to increase the amount available under the facilities to $700 million (from $650 million), extend the terms of the facilities from 364 days (plus one-year term-out) to three years, and change the structure of the facilities from reserves-based to covenant-based (with standard commercial covenants for facilities of this nature).

At the end of the second quarter of 2011, total monetary debt was $682 million and undrawn credit facilities were $385 million. This level of debt represents a debt-to-FFO ratio of 1.4 times, based on trailing twelve months FFO. This level of debt and undrawn credit facilities are within our leverage and liquidity targets, and provide ample capacity to finance our operations.

On August 4, 2011, we filed a Short Form Base Shelf Prospectus with the securities regulatory authorities in each of the provinces of Canada (other than Québec) and a Registration Statement with the United States Securities and Exchange Commission (collectively, the "Shelf Prospectus"). The Shelf Prospectus allows us to issue equity and debt securities with an aggregate offering amount not to exceed $500 million (Canadian) at any time during the ensuing 25-month period. The Shelf Prospectus provides us with ready access to the capital markets in both Canada and the United States in the event that we require external financing.

During the second quarter, we announced several appointments to our management team. Geoffrey Darcy will succeed Shaun Paterson as our Vice President, Marketing. Mr. Paterson is retiring in October 2011 after five years of service to Baytex. Mr. Darcy was formerly Director of North American Physical Crude Oil Trading for Barclays Bank and Vice President of North American Crude Oil Marketing with Nexen Inc. Michael Kaluza joined Baytex as Vice President, Planning. Mr. Kaluza was formerly Chief Operating Officer of Delphi Energy Corp. Brian Ector was promoted to Vice President, Investor Relations. Mr. Ector joined Baytex as Director, Investor Relations in 2009, and was previously a research analyst with Scotia Capital and CIBC World Markets. These management appointments further strengthen Baytex as we execute our growth-and-income business model in our new corporate era.

Additional Information

Our unaudited interim condensed consolidated financial statements for the three months and six months ended June 30, 2011 and 2010 and related Management's Discussion and Analysis of the operating and financial results can be accessed immediately on our website at www.baytex.ab.ca and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to: initial production rates from wells drilled; development plans for our properties, including the number of wells to be drilled in the second half of 2011; our Cliffdale cyclic steam stimulation project at Seal, including our assessment of the results of the third steam injection cycle for our pilot well, the steam-oil ratio for the third steam injection cycle and the completion of a 10-well commercial module of CSS development, including the commencement of steam injection into four additional wells and the drilling of five additional CSS wells; our Kerrobert Thermal project, including the start-up of two additional SAGD well pairs, the number of SAGD drilling locations; our ability to optimize the placement of SAGD well pairs by drilling stratigraphic test wells and the expansion of the steam plant; the natural gas-weighted acquisition in west-central Alberta, including our ability to consolidate it into our existing operations, the 2011 net operating income from the acquired assets, the production from the acquired assets for the last four months of 2011 and the remaining proved plus probable reserves attributable to the acquired assets; our Bakken/Three Forks play in North Dakota, including the timing of completing multi-stage fracture treatments on wells previously drilled and our drilling program for the remainder of 2011; our exploration and development capital expenditures for 2011; the production impact in 2011 of the incremental capital program; our average production rate for 2011; our product mix for 2011; the demand for Canadian heavy oil by U.S. refiners; the existence, operation and strategy of our risk management program for commodity prices and foreign exchange rates; the amount of our undrawn credit facilities at June 30, 2011; our debt to FFO ratio; our liquidity and financial capacity; and the sufficiency of our financial resources to finance 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. The level of future cash dividends will depend on the amount of funds from operations generated by our operations and our prevailing financial circumstances at the time.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. The reader is cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in Baytex's Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2010, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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

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