

**GMXR**

FOR IMMEDIATE RELEASE

FOR ADDITIONAL INFORMATION CONTACT

Jim Merrill	Harry Stahel	Alan Van Horn
Chief Financial Officer	Vice President Finance	Manager, Investor Relations
405.254.5805	405.254.5802	405.254.5839

***GMX RESOURCES INC. Announces Financial and Operational Results for the Three and Six Months Ended June 30, 2011***

**Oklahoma City, Oklahoma, Thursday, August 4, 2011.** *GMX RESOURCES INC.*, NYSE: 'GMXR' (the "Company" or "GMXR"), reports today on the financial and operating results for the second quarter ending June 30, 2011. Please visit the Company's website at [www.gmxresources.com](http://www.gmxresources.com) to view the second quarter presentation, which will be made available no later than 7:30 a.m. CDT, August 4, 2011.

The Company has scheduled a conference call for Thursday, August 4, 2011 at 8:00 a.m. CDT (9:00 a.m. EDT) to discuss the second quarter financial and operating results. To access the call, dial (877) 303-9132 or (408) 337-0136 prior to the conference call start time. Please reference conference code 79577501. A replay of the call will be available after 11:00 a.m. EDT on August 4, 2011 through August 18, 2011 and can be accessed using the following number and pass code: Toll free: (800) 642-1687 or (706) 645-9291. Replay conference code 79577501. In addition, a replay of the call will be archived on our Company website under investor relations / events and presentations. A presentation pertaining to this call will be available on the Company's website no later than 7:30 a.m. CDT, August 4, 2011. [www.gmxresources.com](http://www.gmxresources.com)

**Management Comments**

Michael J. Rohleder, President said: "Our second 2011 production exceeded our guidance and reached a Company record 6.5 BCFE. We drilled four and completed three successful long lateral (~6,500') Haynesville/Bossier horizontal wells during the second quarter. Production for the quarter was up 8% from the previous quarter and 51% from the second quarter of 2010. The production performance of our H/B long lateral program continued to exceed our expectations. In fact, the performance of our 2011 long lateral wells confirms the prior DeGolyer & MacNaughton EUR estimates of 6.5 Bcfe per well. Due to the continued depressed prices for natural gas and the absence of significant cost reduction for services, we have temporarily suspended our Haynesville/Bossier development until economics become competitive with our oil development. We have subleased our fourth H&P FlexRig and will focus all of our remaining 2011 drilling capital expenditure budget on oil development in the Bakken, Niobrara and other East Texas oil targets. Our new production guidance for 2011 is expected to be in a range of 23.8 Bcfe to 24.2 Bcfe, with the midpoint of 24.0 Bcfe, which is representing an increase of 37% from 2010 production. We expect to increase our oil/NGL production and revenue currently 9% and 21%, to 16% and 31% respectively, by year end."

Rohleder continued, "Our overarching goals in the next two years are to accelerate revenues and EBITDA growth to reach profitability sooner, and to reduce our leverage. In order to increase revenue and EBITDA, which leads to a quicker return to positive EPS, we intend to concentrate our capital on the development of our oil programs. In support of these objectives, we acquired an additional 11,449 net acres in North Dakota during the second quarter of 2011, which increases our total acreage in the Bakken/Three Forks to 35,524 net acres. The acreage is located in a very active development area in McKenzie, Billings and Stark Counties and greatly enhances our operated position."

"Transformation to more oil production is the key to accomplishing these goals. We are operational in North Dakota two months ahead of our previous schedule. We now have 600 undrilled 9,500' lateral locations. Our current acreage position provides us with 43 potential operated 1,280-acre units resulting in 172 undrilled Bakken and Three Forks locations with a 45% to 100% average working interest. We have approximately 13 other 1,280-acre units where we could operate that provide another 52 undrilled locations. On July 7, 2011, we spud our first Company-operated horizontal Three Forks well, the Wock 21-2-1H, with a 100% working interest, commencing our oil drilling program in these properties. We have been granted one additional permit, the Frank 31-4-1H in Stark County, and we have 14 permits in process in McKenzie, Billings and Stark counties. We are also participating in two non-operated wells that will spud in the third quarter of 2011, with six more potential non-operated wells based on permits being filed with NDIC."

"In Wyoming, our Niobrara development was delayed to shoot two seismic projects, encompassing 135 and 204 square miles. The 135-square mile Goshen County project in the Northern DJ Basin run by Devon is complete. We are participating in one Devon-operated well in which we have a 29.2% working interest in the third quarter of 2011, and we expect to participate in up to six additional non-operated wells which have been permitted. We are also planning a vertical well in the second half of 2011. Our second seismic project in Platte, Laramie and Southern Goshen Counties will be completed in the fourth quarter of 2011. We will drill a vertical well in this area subsequent to completion and analysis. There are 29 operators and 258 permits in both project areas. Our Niobrara acreage position has approximately 146 640-acre units and we expect to operate between 236 and 380 (65%) of our approximately 584 undrilled 4,000' lateral locations."

"Beginning in the second half of 2011, we plan to commit almost all of our capital expenditures to our oil resources development. We expect our revolver, additional asset sales and potential JV's will provide additional liquidity during the next 12 months. Increasing the oil percentage of our production is expected to have positive economic benefits due to the current value gap that exists between oil and natural gas, and to significantly change the NAV of the Company."

## **Company Highlights for the Three and Six Months Ended June 30, 2011**

### **Operational**

- Production for second quarter of 2011 was a new Company record of 6.5 Bcfe, an increase of 51% over the 4.3 Bcfe of production in the second quarter of 2010. The Company completed a total of three Haynesville/Bossier horizontal "H/B Hz" wells during the second quarter of 2011.
- Production increased by 67% to 12.6 Bcfe in the first half of 2011 compared to 7.5 Bcfe in the first half of 2010.
- Completed well costs for second quarter of 2011 averaged approximately \$8.6 million, which was \$0.1 million less than the first quarter 2011 costs of \$8.7 million.
- In the current natural gas commodity price environment, the Company has elected to temporarily suspend its H/B horizontal drilling until natural gas prices and/or completed well costs support more economical development. The Company will complete its eighth and final 2011 H/B Hz well in the third quarter of 2011.
- Due to temporarily suspending the H/B Hz program, the Company's full year production guidance is expected to decline in a range from 7% to 5% from 25.5 to a range of 23.8 Bcfe to 24.2 Bcfe, with the midpoint of 24.0 Bcfe representing an increase of 37% from the 17.5 Bcfe in production for 2010.
- The Company is currently conducting a 3D seismic shoot of 33 square miles, covering almost all of the Company's contiguous operated acreage in Harrison County, Texas, to aid in a more complete assessment of several oil targets and proven natural gas developments. The 3D seismic shoot is expected to be completed in the second half of 2011.

### **Transformation to Oil**

- **Bakken**
  - In addition to previously announced Bakken acquisitions in the first quarter of 2011, the Company has purchased 11,449 net acres of leasehold in McKenzie, Billings and Stark counties in North Dakota. The purchases involved one transaction with a private company, a successful bid for State of North Dakota leases, and the leasing of several fee mineral rights. The \$28 million total purchase price of this acreage is an average of \$2,448 per net acre.
  - Our total Bakken leasehold acreage is now 35,524 net acres, which is an increase of more than 48% in our net acreage inventory for the Bakken. The average NRI to GMXR associated with these transactions is 82%.
  - These Bakken transactions are strategic to our transition to oil. They represent acreage in 42 new potential units and a 39% increase in the number of potential wells. Significantly, 17 of these units are likely to be operated by GMXR which is a 65% increase in potentially operated units translating into an additional 68 wells.
  - GMXR now owns 600 undrilled 9,500' lateral locations in 150 1,280-acre Bakken units in North Dakota (135 units/540 locations) and Montana (15 units/60 locations). Our position now equates to 172 net operated wells.

- We expect to operate at least 43 1,280-acre units in North Dakota, with working interests averaging more than 45%. We anticipate working interests to ultimately range from 75% to 100%. The 43 units have a potential for 172 locations, which is a eighteen rig-year inventory development program. We have 13 additional possible operated units in North Dakota that could provide another 52 locations.
- The Company is drilling the lateral section of its first Company operated Bakken well in Stark County, North Dakota. The Wock 21-2-1H in Section 2 & 11, Township 140N, Range 98W will test the Three Forks with a 9,500' lateral with a total measured depth of 20,700'. We expect completion of this well in the third quarter of 2011.
- We have received a permit for our second well, the Frank 31-4-1H in Stark County, and are currently in the permitting process for 14 horizontal wells in McKenzie, Billings and Stark Counties and are also planning 14 wells for permitting in the first quarter of 2012.
- The Company has elected to participate in two non-operated wells targeting the Middle Bakken and Three Forks zones to be drilled in the third quarter of 2011. Our working interests are 2% and 25%. We expect to participate in six additional non-operated wells scheduled to be drilled in 2011 with an average working interest of approximately 8.4%.
- **Niobrara**
  - Our N. Mustang Doty-Hill, Goshen county, 135 square mile seismic shoot has been completed with partial processing available. The data confirms GMXR's prior identification of this area as possessing joints, faults and other features favorable for the production of the Niobrara oil system.
  - The Company is currently conducting a 204 square mile 3D seismic shoot that covers the majority of our Platte, Laramie and Southern Goshen County, Wyoming leases and expects to complete this shoot in the second half of 2011.
  - The Company has elected to participate in Devon Energy's Newton Ranches 14-3444H Well located in Section 34-T24N-R64W, plus three more being proposed in Goshen County, Wyoming. This well is within the N. Mustang seismic project area and will test the Niobrara Formation. GMXR has a 29.2% working interest. We believe Devon plans to commence drilling the well in the third quarter of 2011. We expect to participate in three additional Niobrara non-operated wells in 2011 with Devon.
  - In Platte and Laramie Counties, Wyoming, GMXR owns 376 undrilled locations in 94 640-acre Niobrara units of which we expect to operate 70 units with 280 potential wells with an average of 64% working interest. GMXR has an average working interest of 78% in 49 of these units.
  - In Goshen County, Wyoming, GMXR now owns 208 undrilled 4,000' lateral locations in 52 640-acre Niobrara units of which we expect to operate 25 of these units containing 100 potential locations with an average working interest of 45%.
  - The Company plans to begin operations in the Niobrara in the second half of 2011 with one vertical test well before taking the well horizontal in the first quarter of 2012.
  - GMXR now owns 584 undrilled 4,000' lateral locations in 146 640-acre units in the Niobrara. Our position now equates to 190 net operated wells.

## **Financial**

- Net loss applicable to common shareholders was \$15.4 million, or \$0.28 per share, and \$69.8 million, or \$1.43 per share, for the three and six months ended June 30, 2011, respectively.
- As detailed below, non-GAAP adjusted net loss applicable to common shareholders per share<sup>(1)</sup> was \$0.03 and \$0.09 for the three and six months ended June 30, 2011, respectively.
- Lease operating expenses were \$0.43 and \$0.46 per Mcfe for the three and six months ended June 30, 2011, respectively, compared to \$0.52 and \$0.71 per Mcfe for the three and six months ended June 30, 2010, respectively, or a decrease of 17% and 35% per Mcfe, respectively.

- General and administrative expenses were \$1.17 and \$1.17 per Mcfe for the three and six months ended, June 30, 2011, respectively, compared to \$1.44 and \$1.79 per Mcfe for the three and six months ended June 30, 2010, respectively or a decrease of 19% and 35%, respectively.
- Adjusted EBITDA <sup>(1)</sup> was \$21.3 million and \$40.4 million for the three and six months ended June 30, 2011, respectively, compared to \$16.6 million and \$28.5 million for the three and six months ended June 30, 2010, respectively.
- Discretionary cash flow <sup>(1)</sup> of \$13.7 million and \$25.5 million for the three and six months ended June 30, 2011, respectively, compared to \$13.2 million and \$22.0 million for the three and six months ended June 30, 2010, respectively.
- Revised cash capital expenditure budget for 2011 is \$287 million, of which \$101 million is the cash portion of acreage acquisitions and \$186 million is for drilling operations of which we estimate approximately 28% will be spent on oil related activities. As of June 30, 2011, we have made \$192 million of these planned capital expenditures.
- Revised guidance for 2011 adjusted EBITDA <sup>(1)</sup> is expected to be in the range of \$76 to \$81 million.

<sup>(1)</sup> Adjusted net loss available to common shareholders, adjusted EBITDA and discretionary cash flow are non-GAAP measures that are further described and reconciled below in this press release.

### Financial Results for the Three and Six Months Ended June 30, 2011

The Company reported a net loss applicable to common shareholders of \$15.4 million (\$0.28 per basic and fully diluted share) and \$69.8 million (\$1.43 per basic and fully diluted share) for the three and six months ended June 30, 2011, respectively, compared to a net loss applicable to common shareholders of \$3.0 million (\$0.11 per basic and fully diluted share) and net income applicable to common shareholders of \$0.8 million (\$0.03 per basic and fully diluted share) for the three and six months ended 2010, respectively.

Adjusted net loss applicable to common shareholders, a non-GAAP measure adjusting for items set forth below, was \$1.4 million and \$4.4 million, or \$0.03 and \$0.09 per basic and fully diluted share, for the three and six months ended June 30, 2011, respectively. Adjusted net income (loss) is provided as a supplemental financial measure. We believe adjusted net income (loss) provides additional information regarding our operating financial performance and is beneficial to the lenders under our credit facility and the investment community.

Adjusted net loss is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income applicable to common shareholders, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP.

	Three Months Ended		Six Months Ended	
	June 30, 2011		June 30, 2011	
	Amount	Per Share <sup>(1)</sup>	Amount	Per Share <sup>(1)</sup>
(in thousands, except for per share amounts)				
GAAP Net income (loss) applicable to common shareholders	\$ (15,383)	\$ (0.28)	\$ (69,833)	\$ (1.43)
Adjustments:				
Deferred income tax valuation allowance	1,436	0.03	2,868	0.06
Impairment of oil and natural gas properties and assets held for sale	16,861	0.30	65,181	1.33
Unrealized gain on derivative contracts	(5,437)	(0.10)	(4,992)	(0.10)
Ineffectiveness of cash flow hedges	(315)	(0.01)	(722)	(0.01)
Non-cash interest expense <sup>(2)</sup>	1,354	0.02	2,890	0.06
Extinguishment of debt	67	0.00	176	0.00
Adjusted net loss applicable to common shareholders	\$ (1,417)	\$ (0.03)	\$ (4,432)	\$ (0.09)

<sup>(1)</sup> Due to the adjusted net loss applicable to common shareholders for the three and six months ended June 30, 2011, per share amounts are calculated using the weighted average basic number of shares that excludes items that would be

antidilutive. Basic weighted average common shares outstanding for the three and six months ended June 30, 2011 was 55,660,978 and 48,959,825, respectively.

- <sup>(2)</sup> Non-cash interest expense is comprised of the amortization of discounts related to our convertible notes, share lending agreement and deferred premiums on derivative instruments.

The following table summarizes certain key operating and financial results for the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010.

### Summary Operating Data

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
<b>Production:</b>				
Oil (MBbls)	24	24	46	46
Natural gas (MMcf)	5,852	3,592	11,367	6,085
Natural gas liquids (Mgals)	3,678	4,005	6,442	8,023
Gas equivalent production (MMcfe)	6,524	4,308	12,563	7,507
Average daily (MMcfe)	71.7	47.3	69.4	41.5
<b>Average Sales Price:</b>				
Oil (per Bbl)				
Sales price	\$ 100.04	\$ 75.98	\$ 96.41	\$ 75.73
Effect of derivatives, excluding gain or loss from ineffectiveness of derivatives	(1.79)	—	(0.95)	—
Total	\$ 98.25	\$ 75.98	\$ 95.46	\$ 75.73
Natural gas liquids (per gallon)				
Sales price	\$ 0.95	\$ 0.78	\$ 0.91	\$ 0.86
Effect of derivatives, excluding gain or loss from ineffectiveness of derivatives	—	—	—	—
Total	\$ 0.95	\$ 0.78	\$ 0.91	\$ 0.86
Natural gas (per Mcf)				
Sales price	\$ 3.87	\$ 3.55	\$ 3.77	\$ 4.01
Effect of derivatives, excluding gain or loss from ineffectiveness of derivatives	0.68	2.04	0.74	1.80
Total	\$ 4.55	\$ 5.59	\$ 4.51	\$ 5.81
<b>Average sales price (per Mcfe)</b>	\$ 5.04	\$ 5.39	\$ 4.95	\$ 5.93
<b>Operating and Overhead Costs (per Mcfe):</b>				
Lease operating expenses	\$ 0.43	\$ 0.52	\$ 0.46	\$ 0.71
Production and severance taxes	0.03	0.07	0.04	0.14
General and administrative	1.17	1.44	1.17	1.79
<b>Other (per Mcfe):</b>				
Depreciation, depletion and amortization—oil and natural gas properties	\$ 1.81	\$ 1.75	\$ 1.84	\$ 1.70

### Results of Operations for the Three Months Ended June 30, 2011 Compared to the Three Months Ended June 30, 2010

*Oil and Natural Gas Sales.* Oil and natural gas sales during the three months ended June 30, 2011 increased 42% to \$32.9 million compared \$23.2 million in the second quarter of 2010. The increase in oil and natural gas sales was due to a 51.4% increase in production on a Bcfe-basis, a 29.3% increase in oil prices, and a 21.8% increase in the average realized price in natural gas liquids (“NGLs”), offset by a 18.6% decrease in the average realized price of natural gas, excluding ineffectiveness of hedging activities. The average price per barrel of oil, per gallon of natural gas liquids NGLs and Mcf of natural gas received (exclusive of ineffectiveness from derivatives) in the three months ended June 30, 2011 was \$98.25, \$0.95 and \$4.55, respectively, compared to \$75.98, \$0.78 and \$5.59, respectively, in the three months ended June 30, 2010. Our realized sales price for natural gas, excluding the effect of hedges of \$0.68 and \$2.04, for the three months ended June 30, 2011 and 2010, respectively, was approximately 90% and 86% of the average NYMEX closing contract price for the respective periods. In the second quarter of 2011 and 2010, the conversion of natural gas to NGLs produced an upgrade of approximately \$0.31 per Mcf

and \$0.40 per Mcf, respectively, for every Mcf of natural gas produced. This upgrade in value was previously included in the realized price of our natural gas sales. Ineffectiveness of derivative gains (losses) recognized in oil and gas sales of \$0.3 million and \$(1.8) million for the three months ended June 30, 2011 and 2010, respectively, is the result of a difference in the fair value of our cash flow hedges and the fair value of the projected cash flows of a hypothetical derivative based on our expected sales point.

Natural gas production for the three months ended June 30, 2011 increased to 5,852 MMcf compared to 3,592 MMcf for the three months ended June 30, 2010, an increase of 62.9%. The increase in natural gas production resulted from production related to 37.1 net producing H/B horizontal wells that were on-line during the second quarter of 2011 compared to 19.5 net producing Haynesville/Bossier ("H/B") horizontal wells online during the second quarter of 2010. During the second quarter of 2011, we brought on-line three H/B horizontal wells and production from all H/B horizontal wells, including the three H/B horizontal wells brought on-line in the second quarter 2011, which accounted for 78% of total production for the three months ended June 30, 2011 compared to 61% in the same period in 2010. Oil production for the three months ended June 30, 2011 remained the same as of the three months ended June 30, 2010 at 24 MBbls. During the first quarter of 2011, we began to separate and report the production and revenue from our NGLs, compared to prior periods in which we had included NGL production and revenues in our natural gas production and sales amounts. NGL production for the three months ended June 30, 2011 decreased to 3,678 Mgals compared to 4,005 Mgals for the three months ended June 30, 2010, a decrease of 8.1%. This decrease was due to a decline in production in our non-Haynesville production, which has a higher NGL content compared to our H/B horizontal wells.

For the three months ended June 30, 2011, as a result of hedging activities, excluding derivative ineffectiveness, we recognized an increase in natural gas sales of \$3.9 million compared to an increase in natural gas sales of \$7.3 million in the second quarter of 2010. In the second quarter of 2011, hedging, excluding ineffectiveness, increased the average natural gas sales price by \$0.68 per Mcf compared to an increase in natural gas sales price of \$2.04 per Mcf in the second quarter of 2010. The effect of our derivative contracts on oil decreased the average oil sales price \$1.79 per Bbl for the three months ended June 30, 2011 compared to no effect in the same period in 2010.

*Lease Operations.* Lease operations expense increased \$0.6 million, or 26%, for the three months ended June 30, 2011 to \$2.8 million, compared to \$2.2 million for the three months ended June 30, 2010. Lease operations expense, on an equivalent unit of production basis, decreased \$0.09 per Mcfe in the three months ended June 30, 2011 to \$0.43 per Mcfe, compared to \$0.52 per Mcfe for the three months ended June 30, 2010. The decrease in lease operations expense on an equivalent unit basis resulted from an increase in H/B horizontal well production and cost control measures implemented by us during 2010, which lowered lease operating expense on a per Mcfe basis. With little to no incremental increase in lease operations cost from a Cotton Valley vertical well, the significantly larger amount of production from a H/B horizontal well will result in lower per unit lease operations costs. The overall increase in lease operations expense is primarily related to higher gathering costs plus an increase in salt water disposal expense related to the increase in production in the three months ended June 30, 2011 compared to the three months ended June 30, 2010.

*Production and Severance Taxes.* The State of Texas grants an exemption of severance taxes for wells that qualify as "high cost" wells. Certain wells, including all of our H/B wells, qualify for full severance tax relief for a period of ten years or recovery of 50% of the cost of drilling and completions, whichever is less. As a result, refunds for severance tax paid to the State of Texas on wells that qualify for reimbursement are recognized as accounts receivable and offset severance tax expense for the amount refundable. Production and severance taxes decreased 47% to \$0.2 million in the three months ended June 30, 2011 compared to \$0.3 million in the three months ended June 30, 2010.

*Depreciation, Depletion and Amortization.* Depreciation, depletion and amortization expense increased \$4.6 million, or 52%, to \$13.3 million in the three months ended June 30, 2011 compared to \$8.7 million for the three months ended June 30, 2010. The oil and gas properties depreciation, depletion and amortization rate per equivalent unit of production was \$1.81 per Mcfe in the three months ended June 30, 2011 compared to \$1.75 per Mcfe in the three months ended June 30, 2010. This increase in the rate per Mcfe is due to the percentage increase in oil and gas properties subject to amortization exceeding the percentage growth in reserves for the three months ended June 30, 2011.

*Impairment of oil and natural gas properties and assets held for sale.* For the \$16.9 million impairment charge recorded in the second quarter of 2011, \$11.5 million was related to the impairment of oil and gas properties subject to the full cost ceiling test and \$5.4 million was related to a change in value of assets held for sale. The primary factors impacting the full cost method ceiling test are expenditures added to the full cost pool, reserve levels, value of cash flow hedges and natural gas and oil prices, and their associated impact on the present value of estimated future net revenues. Any excess of the net book value is generally written off as an expense. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Natural gas represents 90% of the Company's total production, and as a result, a decrease in natural gas prices can significantly impact the Company's ceiling

test. During the second quarter of 2011, the 12-month average of the first day of the month natural gas price increased 3% from \$4.10 per MMBtu at March 31, 2011 to \$4.21 per MMBtu at June 30, 2011. Even though the 12-month average of the first day of the month natural gas price increased during the second quarter of 2011, the Company recorded impairment expense of \$11.5 million related to oil and gas properties. Of the \$11.5 million related to the impairment of oil and gas properties, \$3.0 million resulted from the net book value of oil and gas properties exceeding the net present value of future net revenues, \$3.4 million related to the decrease in net present value of the cash flow hedges used in the full cost ceiling test and \$5.1 million due to the de-designation of cash flow hedges that could no longer be considered in the full cost ceiling test. The remaining \$5.4 million of the \$16.9 million impairment charge was related to additional impairment on the Company's three drilling rigs, currently classified as assets held for sale, and was based on a change in fair value of the rigs used to calculate the impairment which reflects the sales price of one of the rigs sold in July 2011.

*General and Administrative Expense.* General and administrative expense for the three months ended June 30, 2011 was \$7.6 million compared to \$6.2 million for the three months ended June 30, 2010, an increase of \$1.4 million, or 22%. General and administrative expense per equivalent unit of production was \$1.17 per Mcfe for the second quarter of 2011 compared to \$1.44 per Mcfe for the comparable period in 2010. The increase in general and administrative expense for the three months ended June 30, 2011 compared to the three months ended June 30, 2010 was primarily due to an increase in salaries, wages and related payroll taxes as a result of an increase in employees needed to transition to and develop the Company's oil related acreage expansion. General and administrative expenses include \$1.2 million and \$1.1 million of non-cash compensation expense as of the three months ended June 30, 2011 and 2010, respectively. Non-cash compensation represented 16% and 18% of total general and administrative expenses, for the three months ended June 30, 2011 and 2010, respectively. General and administrative expense has not historically varied in direct proportion to oil and natural gas production because certain types of general and administrative expenses are non-recurring or fixed in nature.

*Interest.* Interest expense for the three months ended June 30, 2011 was \$7.8 million compared to \$4.7 million for the same period in 2010. For the three months ended June 30, 2011 and 2010, interest expense includes non-cash interest expense of \$1.4 million and \$1.7 million, respectively, related to the accounting for convertible bonds, our share lending agreement and deferred premiums on derivative instruments. Cash interest expense for the three months ended June 30, 2011 and 2010 was \$7.7 million and \$2.9 million, respectively, of which \$2.0 million and \$0.6 million, respectively, was capitalized to properties not subject to amortization on the consolidated balance sheets. The increase in cash interest expense of \$4.8 million was mainly due to the Company's issuance and sale of \$200 million aggregate principal amount of 11.375% senior notes due 2019 ("11.375% senior notes") in February 2011.

*Income Taxes.* Income tax for the three months ended June 30, 2011 was a provision of \$1.4 million as compared to a provision of \$2.4 million in the same period in 2010. The income tax expense recognized in the three months ended June 30, 2011 and 2010, respectively, was a result of a change in the valuation allowance on net deferred tax assets caused by a change in deferred tax liabilities primarily related to unrealized gains on derivative contracts designated as hedges where the mark-to-market change on the hedges, net of deferred taxes is recorded to other comprehensive income.

*Net income to non-controlling interest.* Net income to non-controlling interest increased to \$1.7 million for the three months ended June 30, 2011 compared to \$0.6 million for the three months ended June 30, 2010. The increase is due to an increase in the gathering fees earned by our majority-owned subsidiary in which the outside non-controlling interest member is currently allocated 80% of the distributions. The gathering fees earned by the subsidiary increased as a result of an increase in production from the H/B horizontal wells that were completed and brought online.

## **Net Loss and Net Loss Per Share**

*Net Loss and Net Loss Per Share—Three Months Ended June 30, 2011 Compared to Three Months Ended June 30, 2010.* For the three months ended June 30, 2011 we reported a net loss applicable to common shareholders of \$15.4 million and for the three months ended June 30, 2010, we reported a net loss applicable to common shareholders of \$3.0 million. Net loss per basic and fully diluted share was \$0.28 for the second quarter of 2011 compared to net loss per basic and fully diluted share of \$0.11 for the second quarter of 2010. Weighted average-basic shares outstanding increased by 27,479,391 shares from 28,181,587 shares in the second quarter of 2010 to 55,660,978 shares in the second quarter of 2011. There were no dilutive shares for the three months ended June 30, 2011 and 2010, since the Company was in a loss position and all dilutive shares would have been antidilutive.

## **Capital Resources and Liquidity**

Our business is capital intensive. Our ability to grow our reserve base is dependent upon our ability to obtain outside capital and generate cash flows from operating activities to fund our drilling and capital expenditures. Our cash flows from

operating activities are substantially dependent upon crude oil and natural gas prices, and significant decreases in market prices of crude oil or natural gas could result in reductions of cash flow and affect our drilling and capital expenditure plan. To mitigate a portion of our exposure to fluctuations in natural gas prices, we have entered into natural gas swaps, three-way collars and put spreads.

As of June 30, 2011, we had cash and cash equivalents of \$4.9 million and our undrawn borrowing base of \$60.0 million. Through the period ended June 30, 2011, we have funded our operating expenses and capital expenditures through positive operating cash flows, as well as from \$105.3 million raised from the issuance of 22,173,518 shares of our common stock in February 2011, \$25.8 million raised from the issuance of 1,135,565 shares of our 9.25% Series B Cumulative Preferred Stock and \$193.7 million, net of original issue discount, raised from the issuance of our 11.375% senior notes. The outstanding balance of our bank credit facility at the time of the offerings was fully repaid, and we completed a \$50 million tender offer for a portion of our 5.00% convertible senior notes due 2013 ("5.00% convertible notes"). The remaining proceeds from the offerings were used to fund the Niobrara and Bakken acreage acquisitions and future capital expenditures.

We continually review our drilling and capital expenditure plans and may change the amount we spend based on commodity prices, industry conditions and the availability of capital. In the first six months of 2011, our cash outlay for capital expenditures was \$192 million, net of additions to oil and gas properties from issuance of common stock for the Bakken and Niobrara acreage acquisitions. Cash expenditures related to the purchase price of Niobrara and Bakken acreage acquisitions totaled \$61.2 million and \$90.8 million for the three and six months ended June 30, 2011. In the new Bakken acquisitions completed in the second quarter of 2011, the Company purchased an additional 11,449 net acres in the Bakken for a total purchase price of \$28 million, bringing our total Bakken net acres to 35,524.

The revised cash capital expenditure budget for 2011 is \$287 million, of which \$101 million is the cash portion of acreage acquisitions in the Bakken, DJ Basin-Niobrara and East Texas and \$186 million is for drilling operations of which we estimate approximately 28% will be spent on oil related activities. As of June 30, 2011, we have made \$192 million of these planned capital expenditures. The Company has elected to temporarily suspend execution of its H/B horizontal program until natural gas prices or lower completed well costs support more economical development. The Company will complete its eighth and final H/B horizontal well for this calendar year in the third quarter of 2011.

The Company anticipates funding the \$94 million of cash capital expenditures in the second half of 2011 with positive operating cash flow, the unused portion of our revolving bank credit facility, proceeds from sales of assets held for sale, and continued at-the-market sales of our 9.25% Series B Cumulative Preferred Stock.

In order to protect us against the financial impact of a decline in natural gas prices, we have an active hedging program. As of June 30, 2011, we had natural gas hedges in place of 7.8 Bcf for our remaining estimated natural gas production for 2011 at an average hedge floor price of \$6.13 per Mcf. In addition, we have 16.7 Bcf and 4.7 Bcf of natural gas hedged in 2012 and 2013, respectively, at average hedge prices of \$6.08 and \$5.40 per Mcf. As of June 30, 2011, we have also sold put options that would reduce the average hedge floor price if the monthly natural gas contract settlement price is below \$4.18 for 2011, \$4.12 for 2012 and \$3.75 for 2013. If the monthly natural gas contract settlement is below the average sold put price, we will receive the monthly natural gas contract settlement price plus \$1.95 in 2011, \$1.95 in 2012, and \$1.65 in 2013.

As a result of temporarily suspending the H/B horizontal drilling program in the third quarter of 2011, certain hedged natural gas volumes exceeded estimated future production. In order to reduce the amount of hedged volumes, the Company monetized 84,887 Mcf of 2011 hedges and 4.3 Bcfe of 2012 hedges. Net of deferred premiums payable related to these volumes, the Company received \$2.7 million in proceeds.

## **Operational Update**

### **Bakken**

In May 2011, the Company increased its Bakken position with multiple transactions totaling 11,449 net acres. The first of two significant transactions was a purchase and sale agreement for 9,608 net acres at an average cost of \$2,500 per net acre from a private seller located in Billings and Stark Counties, North Dakota. The second transaction was for 1,684 net acres from the State of North Dakota at an average cost of \$2,211 per net acre. Approximately 960 net acres are located in McKenzie County while 724 net acres are located in Billings County. The remaining 157 net acres were acquired through the leasing of several fee mineral rights. These acquisitions bring our total Bakken net acres to 35,524. The Company holds leases in approximately 150 potential 1,280-acre units in Bakken and expects to be the operator in approximately 43 of those units providing a minimum of 172 operated locations. The Company expects the working interest in our operated locations will range from approximately 45% to 100%, with the first three operated wells having an 80%-100% working interest.

In March 2011, the Company was granted its first permit from the North Dakota Industrial Commission (NDIC) for a 1,280-acre spaced unit in Stark County. We spud our first operated Three Forks well, the Wock 21-2-1H, on July 7, 2011 and hold a 100% working interest and an 81% NRI. We expect completion in the third quarter of 2011. The Company has its second permit for the Frank 31-4-1H, Stark County, and is submitting applications for permits for an additional 14 wells in 14 new 1,280-acre units in Stark, McKenzie and Billings Counties. Additionally, we are also preparing 14 permits that will be submitted to the NDIC in Q1 2012. GMX expects to operate 43 units on its North Dakota leasehold. These units have a potential for 172 locations, which is an eighteen rig year inventory. We have 13 additional possible operated units in North Dakota that could provide another 52 locations.

The Company has elected to participate in two non-operated wells targeting both the Middle Bakken and Three Forks zones. The working interests in these non-operated wells are 2% and 25%. The Company anticipates participating in an additional six non-operated wells in 2011 with an average working interest of 8.4%.

The Company has entered into a one-year contract with Paramount Drilling U.S. LLC. The contract began with the spudding of our Wock 21-2-1H well in Stark County.

### **DJ Basin-Niobrara**

As previously announced, the Company has nearly 584 undrilled horizontal locations and has participated in a 3D seismic shoot (135 square miles) initiated by Devon Energy Corporation in an area we call North Mustang-Doty Hill (NMDH) that covers the majority of the Company's leases in Goshen County, Wyoming. The 3D seismic is being utilized to begin our drilling of our NMDH leases. The area consists of 52 gross 640-acre units and 208 potential gross wells, assuming 4 wells per unit. GMXR owns 9,374 net acres, and we expect to operate 25 units containing 100 undrilled locations with an average working interest of at least 45%.

The Company's 3D seismic shoot in Platte and Laramie Counties (204 square miles) should be completed in the second half of 2011. In all, the Company will acquire in excess of 300 square miles of 3D seismic data to aid in our exploitation of the leases. The Company's Platte and Laramie County positions consist of 30,818 net acres with 94 gross 640-acre spaced units providing GMX with potentially Company operated 376 gross wells, assuming 4 wells per unit, averaging a 51% working interest.

The Company has elected to participate in the drilling of the Newton Ranches 14-3444H well with the operator, Devon Energy Corporation, Oklahoma City, Oklahoma, (NYSE: DVN), for its 29.2% working interest. The Newton Ranches 14-3444H well is located in Section 34 Township 24N, Range 64W, in Goshen County, WY. With the benefit of 3D seismic data, the well will be drilled as a 12,216' measured depth horizontal well to test the Niobrara Formation. Three more non-operated wells have been proposed in the area.

We expect to continue to receive additional non-operated proposals given the ramp up of activity by operators in Goshen, Laramie and Platte Counties. We expect that these participations will provide attractive economics, additional data points along with the seismic data that will add to our understanding of the geology of the play and assist in defining the strategy and completion design for the Niobrara development.

## **East Texas Basin**

Based on continuing low natural gas prices and high service costs, the Company has temporarily suspended new drilling in the Haynesville/Bossier at the end of June and we will be completing our eighth and final H/B Hz well for this calendar year in the third quarter. We will focus all of our drilling efforts towards the higher rates of return associated with our oil development opportunities that we have in the Bakken, the DJ Basin-Niobrara and potential oil based opportunities in our East Texas property base.

The Company brought three new H/B Hz wells to production during the second quarter of 2011, which is in line with our objective of having one new well added to production per month. For the second quarter of 2011, our average completed well costs were \$8.57 million which is approximately \$0.1 million less than in the first quarter of 2011. The average stimulated lateral length for the second quarter was 6,589'. The latest long lateral H/B Hz well to come online is the Holt Bosh #5H which has a 30 and 60 running daily average of 7,277 and 6,625 Mcfe/d respectively. The production performance of our longer laterals is in line with our year end estimates of 6.5 Bcfe. The current plan is to resume our H/B drilling program in 2013 and any decision to resume the program at an earlier date would be a function of realized natural gas pricing and completed well costs.

The Company intends to continue with its program of subleasing its fleet of Helmerich and Payne (H&P) Flex Rigs 3™. The Company has subleased H&P rig #420 for another six-month period, starting in July, 2011, and H&P rig #383 has been subleased for the remainder of its term which ends in March 2012. H&P rig #384 is on sublease until February of 2012 and H&P rig # 417 is on sublease until February 2013. At the end of all leases, the Company has the first right to renegotiate new terms on all our H&P rigs.

The Company has begun a 3D seismic shoot of 33 square miles covering almost all of the Company's contiguous operated acreage in Harrison County, Texas which is expected to be completed in the second half of 2011. The benefits of obtaining 3D seismic across our acreage include: (1) identification of additional oil targets for shallow and deep reservoirs in the Glen Rose and Travis Peak and potentially below the Haynesville Bossier gas shale; and (2) a more complete understanding of the joint and fracture systems of our horizontal development of the H/B and Cotton Valley Sands assets. The Company has suspended further testing for hydrocarbons below the H/B until after evaluation of the data from the 3D seismic shoot.

### **Update on 9.25% Series B Cumulative Preferred Share "ATM" Offering**

On December 14, 2010, the Company announced the launch of an "At the Market" offering of shares of our 9.25% Series B Cumulative Preferred Stock with an aggregate amount not to exceed \$62,712,500 million and not to exceed 3,000,000 shares. In the second quarter of 2011, the Company sold 834,927 shares of Series B Cumulative Preferred Stock for approximately \$19.9 million in gross proceeds. Since December 14, 2010, the Company has received gross proceeds from the offering of \$28.1 million and has issued an additional 1,176,734 shares of Series B Cumulative Preferred Stock.

### **Second Quarter 2011 Production and Realized Prices and Guidance for 2011 Production and Adjusted EBITDA**

We had Company record production of 6.5 Bcfe in the second quarter of 2011 representing an increase of 8% from the first quarter of 2011 and 7% more than the Company's previous second quarter guidance of 6.1 Bcfe. Due to temporarily suspending our Haynesville/Bossier Hz drilling program, the Company expects production to decline in a range from 7% to 5% from 25.5 to a range of 23.8 Bcfe to 24.2 Bcfe, with the midpoint of 24.0 Bcfe representing an increase of 37% over the 17.5 Bcfe of production for 2010. The Company is continuing to experience increased production performance from its longer lateral H/B Hz drilling program.

The Company's realized natural gas was 90% of the average NYMEX contract price for the second quarter of 2011. In the first quarter of 2011, the Company's realized natural gas price was 86% of the average NYMEX contract for the quarter. The Company's realized gas price is based on a number of factors including (1) the price of gas at the physical sales points, (2) the amount of gas sold on a firm basis at a first of month index price and the amount of gas sold on a daily basis at the market price during the month of delivery, (3) the strike prices of the bought puts, sold puts, and other financial hedges compared to the NYMEX settlement price, (4) the recognition of option premium income received, less the recognition of option premium expenses paid, and (5) the fees paid to third parties to ship our gas to downstream market points.

Full-year adjusted EBITDA guidance for 2011 is now revised to be in the range of \$76 million to \$81 million due to the Company's temporary suspension of the Haynesville/Bossier drilling operations and the Company's strategic decision to focus on developing the Bakken and Niobrara oil resource plays.

**GMXR is a resource play rich E&P company with development acreage in two oil shale resources in the Bakken (North**

**Dakota / Montana) targeting the Bakken & Sanish-Three Forks and the DJ Basin (Wyoming) targeting the Niobrara Formation; both plays are 90% oil. Our natural gas resources are located in the East Texas Basin, in the Haynesville/Bossier gas shale and the Cotton Valley Sand Formation, where the majority of our acreage is contiguous and held by production. We believe these oil and natural gas resource plays provide a substantial inventory of operated, high probability, repeatable, organic growth opportunities. The Bakken properties contain nearly 600 undrilled, 9,500' lateral length locations, 43 potential operated 1280-acre units and 172 operated locations, with between 45% and 100% working interest. The Niobrara properties contain 584 undrilled, 4,000' lateral length locations, 94 potential operated 640-acre units and 376 operated locations, with an average working interest of 51%. The Haynesville/Bossier and the Cotton Valley Sand locations include 253 net Haynesville/Bossier horizontal locations, and 108 net Cotton Valley Sand horizontal locations. The Company believes multiple basins and both oil and natural gas resource choices provide us with flexibility to allocate capital to achieve the highest risk adjusted rate of return on our portfolio. Please visit [www.gmxresources.com](http://www.gmxresources.com) for more information on the Company.**

This press release includes certain statements that may be deemed to be “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this press release that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. They include statements regarding the Company's financing plans and objectives, drilling plans and objectives, related exploration and development costs, number and location of planned wells, reserve estimates and values, statements regarding the quality of the Company's properties and potential reserve and production levels. These statements are based on certain assumptions and analysis made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments, and other factors it believes appropriate in the circumstances, including the assumption that there will be no material change in the operating environment for the Company's properties. Such statements are subject to a number of risks, including but not limited to the completion of announced acquisitions, commodity price risks, drilling and production risks, risks relating to the Company's ability to obtain financing for its planned activities, risks related to weather and unforeseen events, governmental regulatory risks and other risks, many of which are beyond the control of the Company. Reference is made to the Company's reports filed with the Securities and Exchange Commission for a more detailed disclosure of the risks. For all these reasons, actual results or developments may differ materially from those projected in the forward-looking statements.

**GMX Resources Inc. and Subsidiaries**  
**Consolidated Balance Sheets**  
(dollars in thousands, except share data)  
(Unaudited)

	<b>June 30, 2011</b>	<b>December 31, 2010</b>
<b>ASSETS</b>		
<b>CURRENT ASSETS:</b>		
Cash and cash equivalents	\$ 4,877	\$ 2,357
Accounts receivable – interest owners	4,325	5,339
Accounts receivable – oil and natural gas revenues, net	8,478	6,829
Derivative instruments	18,891	19,486
Inventories	326	326
Prepaid expenses and deposits	1,995	5,767
Assets held for sale	18,854	26,618
Total current assets	<u>57,746</u>	<u>66,722</u>
<b>OIL AND NATURAL GAS PROPERTIES, BASED ON THE FULL COST METHOD</b>		
Properties being amortized	1,021,610	938,701
Properties not subject to amortization	174,021	39,694
Less accumulated depreciation, depletion, and impairment	(713,330)	(630,632)
	<u>482,301</u>	<u>347,763</u>
<b>PROPERTY AND EQUIPMENT, AT COST, NET</b>	68,002	69,037
<b>DERIVATIVE INSTRUMENTS</b>	12,148	17,484
<b>OTHER ASSETS</b>	13,899	6,084
<b>TOTAL ASSETS</b>	<u><u>\$ 634,096</u></u>	<u><u>\$ 507,090</u></u>
<b>LIABILITIES AND EQUITY</b>		
<b>CURRENT LIABILITIES:</b>		
Accounts payable	\$ 11,871	\$ 24,919
Accrued expenses	38,684	33,048
Accrued interest	11,213	3,317
Revenue distributions payable	6,102	4,839
Current maturities of long-term debt	26	26
Total current liabilities	<u>67,896</u>	<u>66,149</u>
<b>LONG-TERM DEBT, LESS CURRENT MATURITIES</b>	341,332	284,943
<b>DEFERRED PREMIUMS ON DERIVATIVE INSTRUMENTS</b>	5,619	10,622
<b>OTHER LIABILITIES</b>	7,419	7,157
<b>EQUITY:</b>		
Preferred stock, par value \$.001 per share, 10,000,000 shares authorized:		
Series A Junior Participating Preferred Stock 25,000 shares authorized, none issued and outstanding	—	—
9.25% Series B Cumulative Preferred Stock, 6,000,000 shares authorized, 3,176,734 shares issued and outstanding as of June 30, 2011 and 2,041,169 shares issued and outstanding as of December 31, 2010 (aggregate liquidation preference \$79,418,350 as of June 30, 2011 and \$51,029,225 as of December 31, 2010)	3	2
Common stock, par value \$.001 per share – 100,000,000 shares authorized, 59,390,455 shares issued and outstanding as of June 30, 2011 and 31,283,353 shares issued and outstanding as of December 31, 2010	59	31
Additional paid-in capital	684,196	531,944
Accumulated deficit	(500,616)	(430,784)
Accumulated other comprehensive income, net of taxes	9,662	15,227
Total GMX Resources' equity	<u>193,304</u>	<u>116,420</u>
Noncontrolling interest	18,526	21,799
Total equity	<u>211,830</u>	<u>138,219</u>
<b>TOTAL LIABILITIES AND EQUITY</b>	<u><u>\$ 634,096</u></u>	<u><u>\$ 507,090</u></u>

**GMX Resources Inc. and Subsidiaries**  
**Consolidated Statements of Operations**  
(dollars in thousands, except share and per share data)  
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2011	2010	2011	2010
OIL AND GAS SALES, net of gain or (loss) from ineffectiveness of derivatives of \$315, \$(1,786), \$722 and \$(1,257), respectively	\$ 32,858	\$ 23,213	\$ 62,235	\$ 44,513
EXPENSES:				
Lease operations	2,836	2,243	5,733	5,354
Production and severance taxes	166	315	549	1,025
Depreciation, depletion, and amortization	13,304	8,731	26,093	15,101
Impairment of oil and natural gas properties and assets held for sale	16,861	—	65,181	—
General and administrative	7,605	6,219	14,683	13,406
Total expenses	40,772	17,508	112,239	34,886
Income (loss) from operations	(7,914)	5,705	(50,004)	9,627
NON-OPERATING INCOME (EXPENSES):				
Interest expense	(7,832)	(4,654)	(15,854)	(8,883)
Loss on extinguishment of debt	(67)	—	(176)	—
Interest and other income	12	9	282	33
Unrealized gain or (loss) on derivatives	5,437	107	4,992	(114)
Total non-operating expense	(2,450)	(4,538)	(10,756)	(8,964)
Income (Loss) before income taxes	(10,364)	1,167	(60,760)	663
INCOME TAX BENEFIT (PROVISION)	(1,436)	(2,369)	(2,868)	3,419
NET (LOSS) INCOME	(11,800)	(1,202)	(63,628)	4,082
Net income attributable to noncontrolling interest	1,746	618	3,158	931
NET (LOSS) INCOME APPLICABLE TO GMX RESOURCES	(13,546)	(1,820)	(66,786)	3,151
Preferred stock dividends	1,837	1,157	3,047	2,313
NET (LOSS) INCOME APPLICABLE TO COMMON SHAREHOLDERS	\$ (15,383)	\$ (2,977)	\$ (69,833)	\$ 838
(LOSS) EARNINGS PER SHARE – Basic	\$ (0.28)	\$ (0.11)	\$ (1.43)	\$ 0.03
(LOSS) EARNINGS PER SHARE – Diluted	\$ (0.28)	\$ (0.11)	\$ (1.43)	\$ 0.03
WEIGHTED AVERAGE COMMON SHARES – Basic	55,660,978	28,181,587	48,959,825	28,140,319
WEIGHTED AVERAGE COMMON SHARES – Diluted	55,660,978	28,181,587	48,959,825	28,140,319

**GMX Resources Inc. and Subsidiaries**  
**Consolidated Statements of Cash Flows**  
(dollars in thousands)  
(Unaudited)

Six Months Ended  
June 30,

	2011	2010
<b>CASH FLOWS DUE TO OPERATING ACTIVITIES</b>		
Net income (loss)	\$ (63,628)	\$ 4,082
Depreciation, depletion, and amortization	26,093	15,101
Impairment of oil and natural gas properties and assets held for sale	65,181	—
Change in fair value of hedges	(4,992)	114
Deferred income taxes	2,867	(3,389)
Non-cash compensation expense	2,155	3,545
Loss on extinguishment of debt	176	—
Non-cash interest expense	4,622	4,545
Other	(722)	1,257
Decrease (increase) in:		
Accounts receivable	(634)	(659)
Inventory and prepaid expenses	(231)	(79)
Increase (decrease) in:		
Accounts payable and accrued liabilities	5,474	(2,340)
Revenue distributions payable	1,263	293
Net cash provided by operating activities	<u>37,624</u>	<u>22,470</u>
<b>CASH FLOWS DUE TO INVESTING ACTIVITIES</b>		
Purchase of oil and natural gas properties	(192,708)	(76,794)
Proceeds from sale of oil and natural gas properties, property, plant, equipment and assets held for sale	2,189	5,986
Purchase of property and equipment	(1,739)	(6,773)
Net cash used in investing activities	<u>(192,258)</u>	<u>(77,581)</u>
<b>CASH FLOWS DUE TO FINANCING ACTIVITIES</b>		
Borrowings on revolving bank credit facility	26,000	26,000
Payments on debt	(118,035)	(50)
Payments on 5.00% Senior Convertible Notes	(50,000)	—
Issuance of 11.375% Senior Notes	193,666	—
Proceeds from sale of common stock	105,324	—
Proceeds from sale of preferred stock	25,809	—
Dividends paid on Series B preferred stock	(3,047)	(2,312)
Fees paid related to financing activities	(16,132)	—
Contributions from non-controlling interest member	385	(956)
Distributions to non-controlling interest member	(6,816)	—
Net cash provided by financing activities	<u>157,154</u>	<u>22,682</u>
<b>NET INCREASE (DECREASE) IN CASH</b>	<b>2,520</b>	<b>(32,429)</b>
<b>CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD</b>	<b>2,357</b>	<b>35,554</b>
<b>CASH AND CASH EQUIVALENTS AT END OF PERIOD</b>	<b><u>\$ 4,877</u></b>	<b><u>\$ 3,125</u></b>
<b>SUPPLEMENTAL CASH FLOW DISCLOSURE</b>		
<b>CASH PAID DURING THE PERIOD FOR:</b>		
INTEREST, Net of amounts capitalized	\$ 3,336	\$ 5,466
INCOME TAXES, Paid (Received)	\$ 1	\$ (30)
<b>NON-CASH INVESTING AND FINANCING ACTIVITIES</b>		
Additions to oil and natural gas properties from issuance of common stock	\$ 31,612	\$ —
(Increase) decrease in accounts payable for property additions	\$ 7,079	\$ (8,648)

**GMX Resources Inc. and Subsidiaries**  
**Non-GAAP Supplemental Information - Discretionary Cash Flows<sup>(1)</sup>**  
(dollars in thousands)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2011	2010	2011	2010
Net (Loss) Income	\$ (11,800)	\$ (1,202)	\$ (63,628)	\$ 4,082
Non cash charges:				
Depreciation, depletion, and amortization	13,304	8,731	26,093	15,101
Impairment and other writedowns	16,861	—	65,181	—
Deferred income taxes	1,436	2,369	2,867	(3,389)
Non-cash compensation expense	996	1,111	2,155	3,545
Loss on extinguishment of debt	67	—	176	—
Non cash interest expense	2,219	2,313	4,622	4,545
Change in fair value of hedges	(5,437)	(107)	(4,992)	114
Other	(314)	1,786	(722)	1,257
Net income attributable to noncontrolling interest	(1,746)	(618)	(3,158)	(931)
Preferred stock dividends	(1,837)	(1,157)	(3,047)	(2,313)
Non-GAAP discretionary cash flow	<u>\$ 13,749</u>	<u>\$ 13,226</u>	<u>\$ 25,547</u>	<u>\$ 22,011</u>
Net cash provided by operating activities	<u>\$ 21,076</u>	<u>\$ 12,010</u>	<u>\$ 37,624</u>	<u>\$ 22,470</u>
Adjustments:				
Changes in operating assets and liabilities	(3,744)	2,991	(5,872)	2,785
Net income attributable to noncontrolling interest	(1,746)	(618)	(3,158)	(931)
Preferred stock dividends	(1,837)	(1,157)	(3,047)	(2,313)
Non-GAAP discretionary cash flow	<u>\$ 13,749</u>	<u>\$ 13,226</u>	<u>\$ 25,547</u>	<u>\$ 22,011</u>

- (1) Discretionary cash flow represents cash provided by operating activities before changes in assets and liabilities less preferred dividends. Discretionary cash flow is presented because we believe it is a useful additional consideration along with net cash provided by operating activities under accounting principles generally accepted in the United States (“GAAP”). Discretionary cash flow is widely accepted as a financial indicator of a natural gas and Oil Company's ability to generate cash that is used to internally fund exploration and development activities and to service debt. This measure is widely used by investors in the valuation, comparison and investment recommendations of companies within the natural gas and oil exploration and production industry. Discretionary cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity. The manner in which we calculate discretionary cash flow may differ from that utilized by other companies. Discretionary cash flow is reconciled to each of net income and net cash provided by operating activities as follows:

**GMX Resources Inc. and Subsidiaries**  
**Non-GAAP Reconciliations - Adjusted EBITDA <sup>(1)</sup>**

Reconciliation of GAAP "Net Income" to Non-GAAP Adjusted EBITDA	Three Months Ended		Trailing Twelve Months Ended	
	June 30,		June 30,	
	2011	2010	2011	2010
(Dollars in Thousands)				
Net Income (Loss)	\$ (11,800)	\$ (1,202)	\$ (206,001)	\$ (44,789)
Adjustments				
Depreciation, depletion, and amortization	13,304	8,731	49,053	30,606
Certain non-cash (income) expenses <sup>(1)</sup>	(930)	2,156	(790)	5,757
Impairment and other writedowns	16,861	—	208,894	50,072
Income taxes	1,436	2,369	2,049	(3,978)
Interest expense	7,832	4,654	25,613	17,480
Change in fair value of hedges	(5,437)	(107)	(4,984)	1,111
(Gain) Loss on extinguishment of debt	67	—	35	4,976
Adjusted EBITDA	\$ 21,333	\$ 16,601	\$ 73,869	\$ 61,235

- (1) Adjusted EBITDA represents earnings before interest, taxes, depletion, depreciation & amortization and includes non-cash compensation, hedging and derivative activities and other expenses per the Company's revolving bank credit facility. Adjusted EBITDA is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors in the valuation, comparison and investment recommendations of companies. Adjusted EBITDA is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our revolving bank credit facility and is used in the financial covenants in our revolving bank credit facility. Adjusted EBITDA is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP.