

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

- QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2011
- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____ to _____

Commission File No. 000-25386

FX ENERGY, INC.

(Exact name of registrant as specified in its charter)

Nevada

(State or other jurisdiction of incorporation or organization)

87-0504461

(IRS Employer Identification No.)

**3006 Highland Drive, Suite 206
Salt Lake City, Utah 84106**

(Address of principal executive offices and zip code)

(801) 486-5555

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer

Non-accelerated filer

Accelerated filer

Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date. **The number of shares of \$0.001 par value common stock outstanding as of August 3, 2011, was 52,460,875.**

FX ENERGY, INC. AND SUBSIDIARIES
Form 10-Q for the Three Months Ended June 30, 2011

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PART I—FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

FX ENERGY, INC. AND SUBSIDIARIES

Consolidated Balance Sheets

(Unaudited)

(in thousands)

	June 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 13,490	\$ 19,740
Receivables:		
Accrued oil and gas sales	3,244	2,617
Joint interest and other receivables	13,294	2,013
VAT receivable	778	392
Inventory	241	242
Other current assets	179	293
Total current assets	<u>31,226</u>	<u>25,297</u>
Property and equipment, at cost:		
Oil and gas properties (successful efforts method):		
Proved	49,269	38,528
Unproved	4,091	3,320
Other property and equipment	9,627	8,853
Gross property and equipment	<u>62,987</u>	<u>50,701</u>
Less accumulated depreciation, depletion and amortization	<u>(14,226)</u>	<u>(12,327)</u>
Net property and equipment	<u>48,761</u>	<u>38,374</u>
Other assets:		
Certificates of deposit	406	406
Loan fees	2,421	2,527
Total other assets	<u>2,827</u>	<u>2,933</u>
Total assets	<u>\$ 82,814</u>	<u>\$ 66,604</u>

-Continued-

The accompanying notes are an integral part of these consolidated financial statements.

FX ENERGY, INC. AND SUBSIDIARIES
Consolidated Balance Sheets
(Unaudited)
(in thousands, except share data)
-Continued-

	June 30, 2011	December 31, 2010
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 7,648	\$ 5,742
Accrued liabilities	1,728	1,343
Total current liabilities	<u>9,376</u>	<u>7,085</u>
Long-term liabilities:		
Notes payable	--	35,000
Asset retirement obligation	736	682
Total long-term liabilities	<u>736</u>	<u>35,682</u>
Total liabilities	<u>10,112</u>	<u>42,767</u>
Stockholders' equity:		
Preferred stock, \$0.001 par value, 5,000,000 shares authorized as of June 30, 2011, and December 31, 2010; no shares outstanding	--	--
Common stock, \$0.001 par value, 100,000,000 shares authorized as of June 30, 2011, and December 31, 2010; 52,315,204 and 45,284,527 shares issued and outstanding as of June 30, 2011, and December 31, 2010, respectively	52	45
Additional paid-in capital	217,753	171,167
Cumulative translation adjustment	7,204	14,013
Accumulated deficit	<u>(152,307)</u>	<u>(161,388)</u>
Total stockholders' equity	<u>72,702</u>	<u>23,837</u>
Total liabilities and stockholders' equity	<u>\$ 82,814</u>	<u>\$ 66,604</u>

The accompanying notes are an integral part of these consolidated financial statements.

FX ENERGY, INC. AND SUBSIDIARIES
Consolidated Statements of Operations and Comprehensive Income (Loss)
(Unaudited)
(in thousands, except per share amounts)

	For the three months ended June 30,		For the six months ended June 30,	
	2011	2010	2011	2010
Revenues:				
Oil and gas sales	\$ 7,789	\$ 5,515	\$ 14,912	\$ 11,543
Oilfield services	1,393	578	1,417	722
Total revenues	9,182	6,093	16,329	12,265
Operating costs and expenses:				
Lease operating expenses	1,031	797	1,801	1,678
Exploration costs	4,054	1,162	6,931	1,524
Property impairment	--	515	--	515
Oilfield services costs	1,200	441	1,341	610
Depreciation, depletion and amortization	931	532	1,668	1,106
Accretion expense	17	19	34	39
Stock compensation	356	351	711	703
General and administrative	2,161	2,253	4,123	3,981
Total operating costs and expenses	9,750	6,070	16,609	10,156
Operating income (loss)	(568)	23	(280)	2,109
Other income (expense):				
Interest expense	(435)	(162)	(1,035)	(318)
Interest and other income	56	17	108	22
Foreign exchange gain (loss)	3,494	(21,961)	10,288	(22,967)
Total other income (expense)	3,115	(22,106)	9,361	(23,263)
Net income (loss)	2,547	(22,083)	9,081	(21,154)
Other comprehensive income (loss)				
Foreign currency translation adjustment	(2,332)	16,808	(6,809)	17,566
Comprehensive income (loss)	\$ 215	\$ (5,275)	\$ 2,272	\$ (3,588)
Net income (loss) per common share				
Basic	\$ 0.05	\$ (0.51)	\$ 0.18	\$ (0.49)
Diluted	\$ 0.05	\$ (0.51)	\$ 0.18	\$ (0.49)
Weighted average common shares outstanding				
Basic	52,315	43,260	49,529	43,238
Dilutive effect of stock options	-	-	-	-
Diluted	52,315	43,260	49,529	43,238

The accompanying notes are an integral part of these consolidated financial statements.

FX ENERGY, INC. AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(Unaudited)
(in thousands)

	For the Six Months Ended June 30,	
	2011	2010
Cash flows from operating activities:		
Net income (loss)	\$ 9,081	\$ (21,154)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	1,668	1,106
Accretion expense	34	39
Amortization of bank fees	289	121
Property impairment	--	515
Stock compensation	711	703
Foreign exchange (gains) losses	(10,298)	22,923
Common stock issued for services	712	635
Increase (decrease) from changes in working capital items:		
Receivables	(12,053)	743
Inventory	1	(9)
Other current assets	114	235
Accounts payable and accrued liabilities	4,037	(832)
Net cash provided by (used in) operating activities	(5,704)	5,025
Cash flows from investing activities:		
Additions to oil and gas properties	(10,593)	(901)
Additions to other property and equipment	(775)	(543)
Net cash used in investing activities	(11,368)	(1,444)
Cash flows from financing activities:		
Proceeds from stock option exercises	128	--
Proceeds from common stock offering, net	45,042	--
Payments made on credit facility	(35,000)	--
Net cash provided by in financing activities	10,170	--
Effect of exchange-rate changes on cash	652	(737)
Net increase (decrease) in cash	(6,250)	2,844
Cash and cash equivalents at beginning of year	19,740	4,225
Cash and cash equivalents at end of period	\$ 13,490	\$ 7,069

The accompanying notes are an integral part of these consolidated financial statements.

FX ENERGY, INC. AND SUBSIDIARIES
Notes to the Consolidated Financial Statements
(Unaudited)

Note 1: Basis of Presentation

In the opinion of management, our financial statements reflect the adjustments, all of which are of a normal recurring nature, necessary for presentation of financial statements for interim periods in accordance with U.S. generally accepted accounting principles (GAAP) and with the instructions to Form 10-Q in Article 10 of SEC Regulation S-X. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of our financial statements, and the reported amounts of revenue and expenses during the reporting periods. Actual results could differ from those estimates. As used in this report, the terms “we,” “us,” “our,” and the “Company” mean FX Energy, Inc., and its subsidiaries, unless the context indicates otherwise.

We condensed or omitted certain information and footnote disclosures normally included in our annual audited financial statements, which we prepared in accordance with GAAP. Our quarterly financial statements should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2010, and our Form 10-Q for the quarter ended March 31, 2011.

We evaluated subsequent events through the date of our financial statement issuance. In August 2011, we determined that one of our exploratory wells was noncommercial, and we have charged our share of dry-hole costs incurred through June 30, 2011, to exploration expense. No other events were identified that had a material impact on the financial statements.

Note 2: Net Income per Share

Basic earnings per share is computed by dividing the net income (loss) applicable to common shares by the weighted average number of common shares outstanding. Diluted earnings per share was computed for the three- and six-month periods ended June 30, 2011, by dividing the net income by the sum of the weighted average number of common shares and the effect of dilutive unexercised stock options. Basic and diluted earnings per share were essentially the same for each of these periods. We had a net loss in the three- and six-month periods ended June 30, 2010. No options were included in the computation of diluted earnings per share for this period because the effect would have been antidilutive.

Outstanding options and unvested restricted stock as of June 30, 2011 and 2010, were as follows:

Balance sheet date:	Options and Unvested Restricted Stock	Price Range
June 30, 2011	1,560,608	\$0.00 - \$10.65
June 30, 2010	2,192,545	\$0.00 - \$10.65

Note 3: Income Taxes

No income tax expense was recognized for the three- and six-month periods ended June 30, 2011 and 2010, due to the reversal of valuation allowances that offset income tax expense for the period. We are required to provide a valuation allowance if it is more likely than not that some portion or all of a deferred tax asset will not be realized. Our ability to realize the benefit of deferred tax assets will depend on the generation of future taxable income through profitable operations and the expansion of exploration and development activities. The market and capital risks associated with achieving the above requirement are considerable, resulting in our conclusion that a full valuation allowance be provided. We are subject to audit by the IRS and various states for the prior three years. We do not believe there will be any material changes in our unrecognized tax positions over the next 12 months, nor has there been a change in our unrecognized tax positions since December 31, 2010. Our policy is to recognize interest and penalties accrued on any unrecognized tax benefits as a component of income tax expense. We do not have any accrued interest or penalties associated with any unrecognized tax benefits, nor was any interest expense related to unrecognized tax benefits recognized during the six months ended June 30, 2011.

Note 4: Business Segments

We operate within two segments of the oil and gas industry: the exploration and production segment and the oilfield services segment. Direct revenues and costs, including exploration costs, depreciation, depletion and amortization costs (“DD&A”), general and administrative costs (“G&A”), and other income directly associated with their respective segments are detailed within the following discussion. Identifiable net property and equipment are reported by business segment for management reporting and reportable business segment disclosure purposes. Current assets, other assets, current liabilities, and long-term debt are not allocated to business segments for management reporting or business segment disclosure purposes.

Reportable business segment information for the three months ended June 30, 2011, the six months ended June 30, 2011, and as of June 30, 2011, is as follows (in thousands):

	Reportable Segments				Total
	Exploration & Production		Oilfield Services	Non-Segmented	
	U.S.	Poland			
Three months ended June 30, 2011:					
Revenues	\$ 1,320	\$ 6,469	\$ 1,393	\$ --	\$ 9,182
Net income (loss) ⁽¹⁾	426	1,577	(36)	580	2,547
Six months ended June 30, 2011:					
Revenues	\$ 2,480	\$12,432	\$ 1,417	\$ --	\$ 16,329
Net income (loss) ⁽¹⁾	880	4,079	(371)	4,493	9,081
As of June 30, 2011:					
Identifiable net property and equipment	\$ 2,130	\$43,535	\$ 3,072	\$ 24	\$ 48,761

- (1) Nonsegmented reconciling items for the second quarter include \$2,161 of G&A costs, \$356 of noncash stock compensation expense, \$380 of other expense, \$17 of corporate DD&A costs and \$3,494 of foreign exchange gains. Nonsegmented reconciling items for the first six months include \$4,123 of G&A costs, \$711 of noncash stock compensation expense, \$928 of other expense, \$33 of corporate DD&A costs, and \$10,288 of foreign exchange gains.

Reportable business segment information for the three months ended June 30, 2010, the six months ended June 30, 2010, and as of June 30, 2010, is as follows (in thousands):

	Reportable Segments				Total
	Exploration & Production		Oilfield Services	Non-Segmented	
	U.S.	Poland			
Three months ended June 30, 2010:					
Revenues	\$ 995	\$ 4,520	\$ 578	\$ --	\$ 6,093
Net income (loss) ⁽¹⁾	400	2,281	(35)	(24,729)	(22,083)
Six months ended June 30, 2010:					
Revenues	\$ 2,079	\$ 9,464	\$ 722	\$ --	\$ 12,265
Net income (loss) ⁽¹⁾	883	6,175	(225)	(27,987)	(21,154)
As of June 30, 2010:					
Identifiable net property and equipment	\$ 906	\$24,544	\$ 2,357	\$ 77	\$ 27,884

(1) Nonsegmented reconciling items for the second quarter include \$2,253 of G&A costs, \$351 of noncash stock compensation expense, \$144 of other expense, \$20 of corporate DD&A costs, and \$21,961 of foreign exchange losses. Nonsegmented reconciling items for the first six months include \$3,980 of G&A costs, \$703 of noncash stock compensation expense, \$296 of other expense, \$41 of corporate DD&A costs, and \$22,967 of foreign exchange losses.

Note 5: Share-Based Compensation

We have several share-based incentive plans. Under these plans, options have been granted at an option price equal to the market value of the stock at the date of grant. The granted options have terms ranging from five to seven years and vest over periods ranging from the date of grant to three years. Under the terms of the stock option award plans, we may also issue restricted stock. Restricted stock awards vest in three equal annual installments from the date of grant.

The following table summarizes option activity for the first six months of 2011:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value
Options outstanding:				
Beginning of year	832,332	\$8.42		
Exercised	(16,499)	7.79		
End of period	<u>815,833</u>	8.44	0.20	
Exercisable at end of period	<u>815,833</u>	8.44	0.20	\$320,142

The following table summarizes option activity for the first six months of 2010:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value
Options outstanding:				
Beginning of year	1,470,441	\$6.47		
Exercised	(12,000)	3.14		
End of period	<u>1,458,441</u>	6.49	0.82	
Exercisable at end of period	<u>1,458,441</u>	6.49	0.82	\$16,380

The aggregate intrinsic value in the tables above represents the total pretax intrinsic value, based on our stock price of \$8.78 as of June 30, 2011, and \$3.62 as of June 30, 2010, which would have been received by stock option holders had all vested in-the-money stock options been exercised as of those dates.

Restricted Stock

During 2010, we issued 373,500 shares of restricted stock, resulting in deferred compensation of \$2,259,675, which will be amortized ratably over a three-year vesting period. Expense recognized during the first six months of 2011 totaled \$376,613. There were no shares of restricted stock issued during the first six months of 2011.

During 2009, we issued 379,500 shares of restricted stock, resulting in unamortized compensation expense of \$1,043,625, which will be amortized ratably over a three-year vesting period. Expense recognized during the first six months of 2011 and 2010 totaled \$173,391 and \$172,154, respectively.

During 2008, we issued 367,000 shares of restricted stock, resulting in unamortized compensation expense of \$1,005,580, which will be amortized ratably over a three-year vesting period. Expense recognized during the first six months of 2011 and 2010 totaled \$160,836 and \$166,217, respectively.

During 2007, we issued 370,925 shares of restricted stock, resulting in unamortized compensation expense of \$2,284,991, which will be amortized ratably over a three-year vesting period. Expense recognized during the first six months of 2010 totaled \$364,294.

The following table summarizes restricted stock activity during the first six months of 2011 and 2010:

	Number of Shares	
	2011	2010
Unvested restricted stock outstanding:		
Beginning of year	746,398	739,535
Issued	--	--
Forfeited	(1,623)	(497)
Vested	--	(4,934)
End of period	744,775	734,104

Note 6: Stockholders' Equity

During the first six months of 2011, we sold 6,900,000 shares of common stock in a registered public offering at a price of \$7.00 per share. After offering costs, the net proceeds from the offering were approximately \$45.0 million, part of which was used to pay down our credit facility balance. See Note 8 for more information. Option holders exercised options to purchase 16,499 shares of common stock during the first half of 2011, which resulted in proceeds of approximately \$128,000. Also during the first six months of 2011, we issued 106,301 shares for the 2010 contribution to our employee benefit plan and 9,500 shares to consultants for services.

In June of 2010, option holders exercised outstanding options to purchase a total of 12,000 shares of common stock at a price of \$3.14 per share by surrendering currently owned shares to pay the exercise price. As a result of this exercise, we issued 2,436 incremental shares. In January of 2010, we issued 216,977 shares for the 2009 contribution to our employee benefit plan. In addition, we issued 6,000 shares to consultants for services.

Note 7: Fair Value Measurements

The accounting standard for fair value measurements provides a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. Fair value is defined as the price that would be received for an asset or the exit price that would be paid to transfer a liability in the principal or most advantageous market in an orderly transaction between market participants on the measurement date. The accounting standard established a fair value hierarchy that requires an entity to maximize the use of observable inputs, where available. The following summarizes the three levels of inputs required as well as the assets and liabilities that we value using those levels of inputs.

- *Level 1*: Unadjusted quoted prices in active markets for identical assets and liabilities.
- *Level 2*: Observable inputs other than those included in Level 1. For example, quoted prices for similar assets or liabilities in active markets or quoted prices for identical assets or liabilities in inactive markets.
- *Level 3*: Unobservable inputs reflecting management's own assumptions about the inputs used in pricing the asset or liability.

A review of fair value hierarchy classifications is conducted on a quarterly basis. Changes in the observability of valuation inputs may result in a reclassification for certain financial assets or liabilities. We did not have any significant nonfinancial assets or nonfinancial liabilities that would be recognized or disclosed at fair value on a recurring basis as of June 30, 2011, nor did we have any assets or liabilities measured at fair value on a nonrecurring basis to report in the first six months of 2011.

Recurring Fair Value

The following table sets forth the financial assets and liabilities that we measured at fair value on a recurring basis by level within the fair value hierarchy. We classify assets and liabilities measured at fair value in their entirety based on the lowest level of input that is significant to their fair value measurement.

Assets and liabilities measured at fair value on a recurring basis consisted of the following as of June 30, 2011 (in thousands):

	<u>June 30, 2011</u>	<u>Level 1⁽¹⁾</u>	<u>Level 2⁽²⁾</u>	<u>Level 3⁽³⁾</u>
Cash equivalents:				
Money market funds	\$6,779	\$6,779	--	--

(1) Quoted prices in active markets for identical assets.

(2) Significant other observable inputs.

(3) Significant unobservable inputs.

Note 8: Notes Payable

We have a \$55 million Senior Reserve Base Lending Facility (the “Facility”) with the Royal Bank of Scotland, ING Bank N.V., and KBC Bank NV. The Facility calls for a periodic interest rate of LIBOR, plus an interest margin of 4.0%, and has a term of five years, with semi-annual borrowing base reductions of \$11 million each beginning on June 30, 2013. The Facility is an interest-only facility until then. An annual unused commitment fee of one-half of the applicable interest margin is charged quarterly based on the average daily unused portion of the expanded credit facility. We amortized approximately \$290,000 of deferred financing costs associated with our existing Facility to interest expense during the first six months of 2011. Payment of the Facility is secured by our assets in Poland and guaranteed by FX Energy, Inc. We used proceeds from the offering described in Note 6 to repay all balances outstanding under the Facility. As of June 30, 2011, we did not have any loans outstanding.

We have access to \$40 million under the Facility until our Kromolice-1, Sroda-4, and Kromolice-2 wells have been on production for 30 days, at which time the full \$55 million becomes available. Proceeds from the Facility are intended to support our development, production, and operating activities in Poland.

Note 9: Capitalized Exploratory Well Costs

We had \$2.3 million and \$604,000 of capitalized costs related to our Plawce-2 and Kutno wells, respectively, which were being drilled at June 30, 2011. In addition, we had capitalized costs of approximately \$342,000 associated with two wells related to our Alberta Bakken project, pending further testing. See Note 11 for more information.

Note 10: Foreign Currency Translation and Risk

During the first six months of 2011, we recorded foreign currency transaction gains of approximately \$10.3 million. This amount was attributable to decreases in the amount of Polish zlotys necessary for FX Energy Poland to satisfy outstanding intercompany and other dollar-denominated loans and unpaid interest. There was a corresponding debit to other comprehensive income for gains attributable to the intercompany loans, which was then offset by translation adjustments related to our other balance sheet accounts.

The following table provides a summary of changes in cumulative translation adjustment (in thousands):

	For the Six Months Ended June 30, 2011
Balance at December 31, 2010	\$ 14,013
Decrease related to gains on intercompany loans	(10,298)
Increase related to translation adjustments	3,489
Balance at June 30, 2011	<u>\$ 7,204</u>

Future transaction gains or losses may be significant given the amount of intercompany loans and the volatility of the exchange rate. Future translation adjustments will also vary in concert with changes in exchange rates. These gains, losses, and adjustments are noncash items for U.S. reporting purposes and have no impact on our actual zloty-based revenues and expenditures in Poland.

We enter into various agreements in Poland denominated in the Polish zloty, which is subject to exchange-rate fluctuations. Our policy is to reduce currency risk by, under ordinary circumstances, transferring dollars to zlotys, or fixing the exchange rate for future transfers of dollars to zlotys, on or about the occasion of making any significant commitment payable in Polish currency, taking into consideration the future timing and amounts of committed costs and the estimated timing and amounts of zloty-based revenues. We do not use derivative financial instruments for trading or speculative purposes.

Note 11: Montana Joint Venture

During the second quarter of 2011, we entered into a joint venture with American Eagle Energy, Inc., and Big Sky Operating LLC, to jointly explore approximately 75,000 acres in the Alberta Bakken formation in Northwest Montana. Our interest in approximately 8,700 acres in the Southwest Cut Bank Sand Unit will be included in the joint exploration program and we will own a one-third interest in the overall project. As part of our agreement, we have agreed to drill wells for the joint venture at customary retail rates.

As consideration for our one-third interest, we agreed to pay a purchase price of approximately \$860,000 in land and associated costs to our partners. The purchase price was reduced by approximately \$349,000, which is the value attributed to the acreage we contributed to the joint venture.

During the same quarter of 2011, we deepened one well in our Southwest Cut Bank Sand Unit and drilled a new test well in the newly acquired acreage. Both wells are pending further tests, including upcoming fracture stimulations. After eliminating all intercompany transactions, we capitalized our share of the cost of both projects, totaling approximately \$342,000.

Note 12: Contingencies

We may face financial sanctions as a result of an oil spill that occurred at our South West Cut Bank Sand Unit in Montana during June of 2011. We are cooperating with the Blackfeet Tribe and the Environmental Protection Agency in completing clean-up, mitigation, and restoration pursuant to an approved plan. Cleanup costs are estimated to be approximately \$150,000, and we have accrued for those costs as of June 30, 2011.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The majority of our operations are in Poland, and we have devoted most of our technical talent and capital expenditures in the last several years to our operations in that country. The decision to devote most of our available capital to this area drives our operating results and the changes to our balance sheet and liquidity. Our operations in Poland, which are a combination of existing production and substantial exploration, have grown considerably. Oil and gas production, oil and gas revenues, cash flow, earnings, oil and gas reserves, and oil and gas expenditures in this area have grown significantly over the last three years.

Our U.S. operations also have an impact. Our U.S. operations are smaller than those in Poland and have not presented the same level of opportunities for expansion; however, we currently are initiating exploration of the Bakken shale in our area, which may warrant further exploration. Our U.S. oil production is a relatively stable source of cash flow, while our domestic oilfield services provide varying amounts of cash flow depending on third-party drilling activities in the area. This, too, is reflected in our operating results.

Results of Operations by Business Segment

Quarter Ended June 30, 2011, Compared to the Same Period of 2010

Exploration and Production Segment

Gas Revenues. Revenues from gas sales were \$6.5 million during the second quarter of 2011, compared to \$4.5 million during the same quarter of 2010. New production at our Sroda-4 well, which began production in late December 2010, was an important component in significantly increased 2011 second quarter natural gas production and revenues.

A summary of the amount and percentage change, as compared to the respective prior-year period, for gas revenues, average gas prices, and gas production volumes for the quarters ended June 30, 2011 and 2010, is set forth in the following table:

	For the Quarter Ended June 30,		Change
	2011	2010	
Gas revenues	\$6,469,000	\$4,520,000	+43%
Average price (per thousand cubic feet)	\$6.36	\$4.91	+30%
Production volumes (thousand cubic feet)	1,017,500	919,700	+11%

In addition to our increased production, three factors resulted in higher gas revenues during the 2011 quarter. First, the Polish low-methane tariff, which serves as the reference price for our gas sales agreements, was 10% higher during the second quarter of 2011 compared to the same quarter of 2010. The increase was a function of two separate price increases by the Polish utility regulator during the second half of 2010. Second, period-to-period strength in the Polish zloty against the U.S. dollar increased our U.S. dollar-denominated gas prices. The average exchange rate during the second quarter of 2011 was 2.75 zlotys per U.S. dollar. The average exchange rate during the second quarter of 2010 was 3.16 zlotys per U.S. dollar, a change of approximately 13%. Third, with the addition of production from Sroda-4, where we receive approximately 86% of the low-methane tariff, our weighted average price per thousand cubic feet of natural gas increased slightly.

The Polish Energy Regulatory Office approved new gas tariffs as of July 1, 2011, which become effective for us on August 1, 2011. The low-methane tariff was increased by 12.5%.

During the third quarter of 2011, all of our producing wells may be shut in for up to two weeks for annual maintenance and pressure testing. Accordingly, we expect third quarter production and gas revenues may be lower than second quarter levels.

Oil Revenues. Oil revenues were \$1.3 million for the second quarter of 2011, a 33% increase from \$1.0 million recognized during the second quarter of 2010. Production levels decreased approximately 1% from 2010 to 2011. The most significant factor in the increase in oil revenues was the higher prices received during the second quarter of 2011. Our average oil price during the second quarter of 2011 was \$89.95 per barrel, a 34% increase from \$67.12 per barrel received during the same quarter of 2010.

A summary of the amount and percentage change, as compared to the respective prior-year period, for oil revenues, average oil prices, and oil production volumes for the quarters ended June 30, 2011 and 2010, is set forth in the following table:

	For the Quarter Ended June 30,		Change
	2011	2010	
Oil revenues	\$1,320,000	\$995,000	+33%
Average price (per barrel)	\$89.95	\$67.12	+34%
Production volumes (barrels)	14,680	14,800	-1%

Lease Operating Costs. Lease operating costs of \$1.0 million during the second quarter of 2011 were 29% higher than the second quarter 2010 amount of \$797,000. During the second quarter of 2011, we had a small oil leak in our Southwest Cut Bank Sand Unit in Montana. Cleanup costs are estimated to be approximately \$150,000, and we have accrued for those costs as of June 30, 2011. See Note 12 for additional information. The remaining increase was due to operating costs associated with new production at our Sroda-4 and Kromolice-1 wells.

Exploration Costs. Our exploration costs consist of geological and geophysical costs and the costs of exploratory dry holes. Exploration costs were \$4.1 million during the second quarter of 2011, compared to \$1.2 million during the same period of 2010, an increase of 249%. Second quarter 2011 exploration costs included approximately \$1.5 million associated with our Lisewo southeast three-dimensional, or 3-D, seismic survey, and \$4.8 million associated with new two-dimensional, or 2-D, seismic surveys at our 100%-owned concessions in Poland. These costs were offset by \$2.8 million of seismic costs that will be reimbursed by the Polish Oil and Gas Company, or PGNiG, following its agreement to farm-in to our Warsaw South concession. Subsequent to June 30, 2011, we made the determination that our Machnatka well, which was being drilled in our Warsaw South concession, did not find commercial quantities of oil or gas. Accordingly, we have charged to exploration expense our share of dry-hole costs incurred through June 30, 2011, of \$232,000. Under the terms of a joint operating agreement, our partner agreed to pay 100% of the costs of the well to a depth of 3,558 meters. After reaching that depth, the partners agreed to continue drilling to a depth of approximately 4,500 meters. Our share of the dry-hole costs is equal to 51% of the incremental drilling costs incurred drilling the additional 952 meters. During the second quarter of 2010, \$872,000 of costs associated with our Zakowo workover project incurred during the quarter were written off as dry-hole costs. Second quarter 2010 geological and geophysical costs were primarily associated with 2-D seismic surveys on our 100%-owned acreage in Poland.

Property Impairment. Second quarter 2010 remediation efforts at our Kleka well failed to restore commercial production. Accordingly, we impaired the remaining capital costs for the well of approximately \$515,000 during the second quarter of 2010. We had no property impairments during the second quarter of 2011.

DD&A Expense - Exploration and Production. DD&A expense for producing properties was \$685,000 for the second quarter of 2011, an increase of 101% compared to \$340,000 during the same period of 2010. Higher DD&A expense in 2011 was due in part to new depreciation expense at our Sroda-4 property, which we began to depreciate when production began in December 2010. In addition, we recorded higher depreciation expense at our Roszkow well due to depreciating existing costs over a smaller reserve base because of year-end 2010 negative reserve revisions.

Accretion Expense. Accretion expense was \$17,000 and \$19,000 for the second quarter of 2011 and 2010, respectively. Accretion expense is related entirely to our Asset Retirement Obligation associated with expected future plugging and abandonment costs.

Oilfield Services Segment

Oilfield Services Revenues. Oilfield services revenues were \$1.4 million during the second quarter of 2011, an increase of 141% compared to \$578,000 for the second quarter of 2010. We drilled three wells for third parties, including those drilled for our Alberta Bakken joint venture, during the second quarter of 2011, along with additional well service work. During the second quarter of 2010, we drilled three shallow wells for third parties. Oilfield services revenues will continue to fluctuate from period to period based on market demand, weather, the number of wells drilled, downtime for equipment repairs, the degree of emphasis on utilizing our oilfield servicing equipment on our Company-owned properties, and other factors.

Oilfield Services Costs. Oilfield services costs were \$1.2 million during the second quarter of 2011, compared to \$441,000 during the same period of 2010. Oilfield services costs will also continue to fluctuate period to period based on market demand, weather, the number of wells drilled, downtime for equipment repairs, the degree of emphasis on utilizing our oilfield servicing equipment on our Company-owned properties, and other factors.

DD&A Expense – Oilfield Services. DD&A expense for oilfield services was \$229,000 during the second quarter of 2011, compared to \$173,000 during the same period of 2010. The quarter-to-quarter increase was primarily due to recent capital additions being depreciated.

Nonsegmented Information

G&A Costs. G&A costs were \$2.2 million during the second quarter of 2011, compared to \$2.3 million during the second quarter of 2010. The decrease is primarily due to lower compensation costs in 2011 offsetting higher legal, investor relations, and travel costs.

Stock Compensation (G&A). For the three-month periods ended June 30, 2011 and 2010, we recognized \$356,000 and \$351,000, respectively; of stock compensation expense related to the amortization of unexercised options and restricted stock.

Interest and Other Income (Expense). Interest and other income was \$55,000 during the second quarter of 2011, an increase of \$38,000, compared to \$17,000 during the same period of 2010. The increase was a reflection of higher cash balances available for investment. During the second quarter of 2011, we incurred \$435,000 in interest expense, which included \$148,000 of amortization of previously incurred loan fees and \$275,000 in commitment fees. During the second quarter of 2010, we incurred \$162,000 in interest expense, which included \$61,000 of amortization of previously incurred loan fees.

Foreign Exchange Gain (Loss). As discussed in Note 10 to the financial statements, during the second quarter of 2011, we recorded foreign currency transaction gains of approximately \$3.5 million, principally attributable to decreases in the amount of Polish zlotys necessary to satisfy outstanding intercompany dollar-denominated loans. We recorded foreign exchange losses of approximately \$21.9 million during the same quarter of 2010, which were also principally related to our intercompany loans. During the second quarter of 2011, the zloty strengthened by approximately 3% against the U.S. dollar from the beginning to the end of the quarter, which caused us to recognize foreign currency transaction gains. Conversely, during the second quarter of 2010, the zloty weakened by approximately 18% against the U.S. dollar from the beginning to the end of the quarter, which caused us to recognize foreign currency transaction losses.

Six Months Ended June 30, 2011, Compared to the Same Period of 2010

Exploration and Production Segment

Gas Revenues. Revenues from gas sales were \$12.4 million during the first half of 2011, compared to \$9.5 million during the same period of 2010. Higher natural gas prices combined with new production from our Sroda-4 and Kromolice-1 wells to produce the higher revenues.

A summary of the amount and percentage change, as compared to the respective prior-year period, for gas revenues, average gas prices, and gas production volumes for the six months ended June 30, 2011 and 2010, is set forth in the following table:

	For the Six Months Ended June 30,		Change
	2011	2010	
Revenues	\$12,432,000	\$9,464,000	+31%
Average price (per thousand cubic feet)	\$6.24	\$5.15	+21%
Production volumes (thousand cubic feet)	1,992,400	1,837,500	+8%

We recognized a 21% increase in natural gas prices period over period. The Polish low-methane tariff, which serves as the reference price for our gas sales agreements, was 10% higher during the first half of 2011 compared to the same quarter of 2010. The increase was a function of two separate price increases by the Polish utility regulator during the second half of 2010. In addition, period-to-period strength in the Polish zloty against the U.S. dollar increased our U.S. dollar-denominated gas prices. The average exchange rate during the first half of 2010 was 3.02 zlotys per U.S. dollar. The average exchange rate during the first half of 2011 was 2.82 zlotys per U.S. dollar, a change of approximately 7%. Also, with the addition of production from Sroda-4, where we receive approximately 86% of the low-methane tariff, our weighted average price per thousand cubic feet of natural gas increased slightly.

As discussed above, the Polish Energy Regulatory Office approved new gas tariffs as of July 1, 2011, which become effective for us on August 1, 2011. The low-methane tariff was increased by 12.5%.

During the third quarter of 2011, all of our producing wells may be shut in for up to two weeks for annual maintenance and pressure testing. Accordingly, we expect third quarter production and gas revenues may be lower than second quarter levels.

Oil Revenues. Oil revenues were \$2.5 million for the first half of 2011, a 19% increase from the \$2.1 million recognized during the first half of 2010. Production from our U.S. properties declined 6% during the first half of 2011. The most significant factor in the increase in oil revenues was the higher prices received during the first half of 2011. Our average oil price during the first half of 2011 was \$85.89 per barrel, a 27% increase from \$67.59 per barrel received during the same period of 2010.

A summary of the amount and percentage change, as compared to the respective prior-year period, for oil revenues, average oil prices, and oil production volumes for the six months ended June 30, 2011 and 2010, is set forth in the following table:

	For the Six Months Ended June 30,		Change
	2011	2010	
Revenues	\$2,480,000	\$2,079,000	+19%
Average price (per barrel)	\$85.89	\$67.59	+27%
Production volumes (barrels)	28,865	30,766	-6%

Lease Operating Costs. Lease operating costs were \$1.8 million during the first half of 2011, compared to \$1.7 million during the first half of 2010. During the second quarter of 2011, we had a small oil leak at our Southwest Cut Bank Sand Unit in Montana. Cleanup costs are estimated to be approximately \$150,000, and we have accrued for those costs as of June 30, 2011. See Note 12 for additional information. Operating costs associated with new production at our Sroda-4 and Kromolice-1 wells in 2011 were offset by the removal of costs associated with our Kleka and Wilga wells, which did not produce during 2011.

Exploration Costs. Our exploration costs consist of geological and geophysical costs and the costs of exploratory dry holes. Exploration costs were \$6.9 million during the first half of 2011, compared to \$1.5 million during the same period of 2010, an increase of 355%. The period-to-period increase is attributable to our increased seismic projects in 2011 compared to 2010. First half 2011 exploration costs included approximately \$1.5 million associated with our Lisewo southeast 3-D seismic survey, \$7.3 million associated with new 2-D seismic surveys at our 100%-owned concessions in Poland, and approximately \$600,000 associated with other geological and geophysical studies. These costs were offset by \$2.8 million of seismic costs that will be reimbursed by PGNiG following its agreement to farm-in to our Warsaw South concession. Subsequent to June 30, 2011, we made the determination that our Machnatka well, which was being drilled in our Warsaw South concession, did not find commercial quantities of oil or gas. Accordingly, we have charged to exploration expense our share of dry-hole costs incurred through June 30, 2011, of \$232,000. Under the terms of a joint operating agreement, our partner agreed to pay 100% of the costs of the well to a depth of 3,558 meters. After reaching that depth, the partners agreed to continue drilling to a depth of approximately 4,500 meters. Our share of the dry-hole costs is equal to 51% of the incremental drilling costs incurred drilling the additional 952 meters. First half 2010 geological and geophysical costs were primarily associated with 2-D seismic surveys on our 100%-owned acreage in Poland and \$872,000 of dry-hole costs associated with our Zakowo project discussed earlier.

Property Impairment. First half 2010 remediation efforts at our Kleka well failed to restore commercial production. Accordingly, we impaired the remaining capital costs for the well of approximately \$515,000 during the first half of 2010. We had no property impairments during the first half of 2011.

DD&A Expense - Exploration and Production. DD&A expense for producing properties was \$1.2 million for the first half of 2011, an increase of 63% compared to \$729,000 million during the same period of 2010. Higher DD&A expense in 2011 was due in part to new depreciation expense at our Sroda-4 property, which we began to depreciate when production began in December 2010. In addition, we recorded higher depreciation expense at our Roszkow well due to depreciating existing costs over a smaller reserve base because of year-end 2010 negative reserve revisions.

Accretion Expense. Accretion expense was \$34,000 and \$39,000 for the first half of 2011 and 2010, respectively. Accretion expense is related entirely to our Asset Retirement Obligation.

Oilfield Services Segment

Oilfield Services Revenues. Oilfield services revenues were \$1.4 million during the first half of 2011, an increase of 96%, compared to \$722,000 for the first half of 2010. We drilled four wells for third parties, including those drilled for our Alberta Bakken joint venture, during the first half of 2011, along with additional well service work. During the first half of 2010, we drilled three shallow wells for third parties. Oilfield services revenues will continue to fluctuate from period to period based on market demand, weather, the number of wells drilled, downtime for equipment repairs, the degree of emphasis on utilizing our oilfield servicing equipment on our Company-owned properties, and other factors.

Oilfield Services Costs. Oilfield services costs were \$1.3 million during the first half of 2011, compared to \$610,000 during the same period of 2010. Oilfield services costs will also continue to fluctuate period to period based on market demand, weather, the number of wells drilled, downtime for equipment repairs, the degree of emphasis on utilizing our oilfield servicing equipment on our Company-owned properties, and other factors.

DD&A Expense – Oilfield Services. DD&A expense for oilfield services was \$448,000 during the first half of 2011, compared to \$336,000 during the same period of 2010. The period-to-period increase was primarily due to new depreciation from capital additions in 2010 and 2011.

Nonsegmented Information

G&A Costs. G&A costs were \$4.1 million during the first half of 2011, compared to \$4.0 million during the first half of 2010, an increase of \$142,000. Higher legal, investor relations, and travel costs were mostly offset by lower compensation costs in the first half of 2011.

Stock Compensation (G&A). For the six-month periods ended June 30, 2011 and 2010, we recognized \$711,000 and \$703,000, respectively, of stock compensation expense related to the amortization of unexercised options and restricted stock purchase rights.

Interest and Other Income (Expense). Interest and other income was \$108,000 during the first half of 2011, an increase of \$86,000 compared to \$22,000 during the same period of 2010. The increase was a reflection of higher cash balances available for investment. During the first half of 2011, we incurred \$1.0 million in interest expense, which included \$290,000 of amortization of previously incurred loan fees and \$275,000 in commitment fees. During the first half of 2010, we incurred \$318,000 in interest expense, which included \$123,000 of amortization of previously incurred loan fees.

Foreign Exchange Loss. As discussed in Note 10 to the financial statements, during the first half of 2011, we recorded foreign currency transaction gains of approximately \$10.3 million, principally attributable to decreases in the amount of Polish zlotys necessary to satisfy outstanding intercompany dollar-denominated loans and unpaid interest to FX Energy, Inc. During the first half of 2011, the zloty strengthened by approximately 7% against the U.S. dollar from the beginning to the end of the period, which caused us to recognize foreign currency transaction gains. Foreign currency transaction losses during the first half of 2010 were \$22.9 million. During the first half of 2010, the zloty weakened by approximately 19% against the U.S. dollar from the beginning to the end of the period, which caused us to recognize foreign currency transaction losses.

Liquidity and Capital Resources

For much of our history, we have financed our operations principally through the sale of equity securities, bank borrowings, and agreements with industry participants that funded our share of costs in certain exploratory activities in return for an interest in our properties. However, as our oil and gas production has increased in Poland in the last several years and as higher oil prices have improved the profitability of our U.S. production, our internally generated cash flow has become a significant source of operations financing.

Following a registered public offering of 6.9 million shares of common stock, which resulted in net proceeds to us of approximately \$45.0 million, in March of 2011 we paid off all amounts previously outstanding under our credit facility. As of June 30, 2011, we had cash and cash equivalents of \$13.5 million and working capital of \$21.8 million.

2011 Liquidity and Capital

Working Capital (current assets less current liabilities). Our working capital was \$21.8 million as of June 30, 2011, an increase of \$3.6 million from December 31, 2010. Our current assets at June 30, 2011, included approximately \$10.4 million in receivables from PGNiG related to its agreement to farm-in to our Warsaw South concession area, and \$3.2 million in accrued oil and gas sales from both the United States and Poland. Our current liabilities at quarter-end included approximately \$6.2 million in costs related to capital and exploration projects in Poland.

Operating Activities. Net cash used in operating activities was \$5.7 million during the first six months of 2011, compared to net cash provided by operating activities of \$5.0 million during the first six months of 2010. Higher revenues in 2011 were offset by increases in exploration spending and increases in receivables from our joint venture partner in Poland.

Investing Activities. During the first six months of 2011, we used cash of \$11.4 million in investing activities. We used \$6.5 million for current-year capital additions in Poland, \$1.1 million for current-year capital additions in the United States, \$775,000 for capital additions in our office and drilling equipment, and \$3.1 million to pay accounts payable related to prior-year capital costs. During the first six months of 2010, we used cash of \$1.4 million in investing activities. We used \$305,000 for capital additions in Poland and \$245,000 related to our proved properties in the United States, used \$352,000 to pay accounts payable related to prior-year capital costs, and used \$542,000 for capital additions in our office and drilling equipment.

Financing Activities. During the first half of 2011, we issued 6.9 million shares of common stock in a registered public offering, which resulted in net proceeds to us, after offering costs, of approximately \$45.0 million. We used \$35.0 million of those proceeds to repay amounts outstanding under our credit facility. We also received proceeds of \$128,000 from the exercise of stock options. There were no similar transactions during the first half of 2010.

Our Capital Resources and Future Expenditures

Our anticipated sources of liquidity and capital for 2011 include our working capital of \$21.8 million at June 30, 2011, available credit of \$55 million under our credit facility when we meet the benchmarks discussed below, cash available from our operations, and proceeds from the possible sale of securities.

We currently have a \$55 million credit facility with The Royal Bank of Scotland, ING Bank N.V., and KBC Bank NV. The credit facility calls for a periodic interest rate of LIBOR plus 4.0% and has a term of five years, with semi-annual borrowing base reductions of \$11 million each beginning on June 30, 2013. The credit facility is an interest-only facility until June 2013. As of June 30, 2011, we had no amounts outstanding under the credit facility. We have access to \$40 million under the credit facility until our Kromolice-1, Sroda-4, and Kromolice-2 wells have been in production for 30 days, at which time the full \$55 million becomes available. We expect to reach this benchmark in the second half of 2011. Proceeds from the credit facility are intended to support our operating activities in Poland. Further, we believe our total credit line could be expanded, even without including our recent 2011 Lisewo-1 discovery, in a revised credit facility.

We expect production from our KSK wells to increase funds available for exploration and development over 2010 levels. Our Winna Gora well is expected to begin production in 2012. In addition, in early 2011, we drilled and completed the successful Lisewo-1 well in our Fences concession, which we expect to further increase revenue in 2013.

We have an effective universal shelf registration statement under the Securities Act of 1933 under which we may sell up to \$200 million of equity or debt securities of various kinds. In December 2010, we sold 1.5 million shares of stock for \$9.0 million in a registered public offering, which resulted in net proceeds to us of approximately \$8.4 million. Also in December 2010, we entered into an agreement to possibly sell up to \$50 million in common stock during the next two years in at-the-market transactions. Through the date of this filing, we have not sold any stock under that agreement. As discussed above, in March 2011, we sold 6.9 million shares of stock for \$48.3 million, which resulted in net proceeds to us of approximately \$45.0 million. The remaining \$92.7 million balance of securities available for sale under the registration statement is available for sale at any time, subject to market conditions and our ability to access the capital markets, to further finance our exploration and development plans in Poland and for other corporate purposes.

We expect our primary use of cash for 2011 will be for our exploration and development activities, most of which will be in Poland. We expect the cost of these activities to range from \$60 to \$70 million for 2-D and 3-D seismic data acquisition and analysis, production facilities for existing discoveries, and additional exploration drilling. The actual amount of our expenditures will depend on ongoing exploration results; the pace at which PGNiG, our operating partner in the Fences project area, determines to participate; the availability of drilling and other exploration resources; and the amount of capital we obtain from the various sources discussed above. Our various sources of liquidity and capital outlined above should more than enable us to meet our capital needs in Poland and the United States for the next 12 months.

Based on current conditions, we presently expect our exploration and development programs will continue in spite of uncertain global economic conditions; however, in recognition of the ongoing economic downturn, we plan to continue, as we have in prior years, matching capital spending with our cash on hand, expected discretionary cash flow, increased debt capacity, and proceeds from the sale of securities. We have the ability to control the timing and amount of most of our future capital and exploration costs.

We may incur operating losses in future periods, and we continue to fund substantial exploration and development in Poland. We have a history of operating losses. From our inception in January 1989 through June 30, 2011, we have incurred cumulative net losses of approximately \$152 million. Despite our recent and expected future increases in production and revenues, our exploration and production activities may continue to result in net losses in future years, depending on the success of our drilling activities in Poland and the United States and whether we generate sufficient revenues to cover related operating expenses. While revenues from our operations exceed our fixed operating and overhead costs, we reported negative cash flow from operating activities during the first half of 2011.

We may also seek to obtain additional funds for future capital investments from the sale of partial property interests or arrangements such as those recently negotiated for our Kutno and Warsaw South project areas, in which industry participants are bearing the initial exploration costs to earn an interest in the project or other arrangements, all of which may dilute the interest of our existing stockholders or our interest in the specific project financed.

We will allocate our existing capital, as well as funds we may obtain in the future, among our various projects at our discretion. We may change the allocation of capital among the categories of anticipated expenditures depending upon future events. For example, we may change the allocation of our expenditures based on the actual results and costs of future exploration, appraisal, development, production, property acquisition, and other activities. In addition, we may have to change our anticipated expenditures if costs of placing any particular discovery into production are higher, if the field is smaller, or if the commencement of production takes longer than expected.

New Accounting Pronouncements

We have reviewed all other recently issued, but not yet adopted, accounting standards in order to determine their effects, if any, on our consolidated results of operations, financial position, and cash flows. Based on that review, we believe that none of these pronouncements will have a significant effect on current or future earnings or operations.

Critical Accounting Policies

A summary of our significant accounting policies is included in Note 1 of our Consolidated Financial Statements contained in our annual report on Form 10-K for the year ended December 31, 2010. We believe the application of these accounting policies on a consistent basis enables us to provide financial statement users with useful, reliable, and timely information about our earnings results, financial condition, and cash flows.

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires our management to make judgments, estimates, and assumptions regarding uncertainties that affect the reported amounts presented and disclosed in the financial statements. Our management reviews these estimates and assumptions, which are based on historical experience, changes in business conditions, and other relevant factors that it believes to be reasonable under the circumstances. In any given reporting period, actual results could differ from the estimates and assumptions used in preparing our financial statements.

Critical accounting policies are those that may have a material impact on our financial statements and also require management to exercise significant judgment due to a high degree of uncertainty at the time the estimate is made. Our senior management has discussed the development and selection of our accounting policies, related accounting estimates, and the disclosures set forth below with the Audit Committee of our Board of Directors. We believe our critical accounting policies include those addressing the recoverability and useful lives of assets, the retirement obligations associated with those assets, and the estimates of oil and gas reserves.

Forward-Looking Statements

This report contains statements about the future, sometimes referred to as “forward-looking” statements. Forward-looking statements are typically identified by the use of the words “believe,” “may,” “could,” “should,” “expect,” “anticipate,” “estimate,” “project,” “propose,” “plan,” “intend,” and similar words and expressions. We intend that the forward-looking statements will be covered by the safe harbor provisions for forward-looking statements contained in Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Statements that describe our future strategic plans, goals, or objectives are also forward-looking statements.

Readers of this report are cautioned that any forward-looking statements, including those regarding us or our management's current beliefs, expectations, anticipations, estimations, projections, proposals, plans, or intentions, are not guarantees of future performance or results of events and involve risks and uncertainties, such as the future timing and results of drilling individual wells and other exploration and development activities; future variations in well performance as compared to initial test data; future events that may result in the need for additional capital; the prices at which we may be able to sell oil or gas; fluctuations in prevailing prices for oil and gas; our ability to complete the acquisition of targeted new or expanded exploration or development prospects; uncertainties of certain terms to be determined in the future relating to our oil and gas interests, including exploitation fees, royalty rates, and other matters; future drilling and other exploration schedules and sequences for various wells and other activities; uncertainties regarding future political, economic, regulatory, fiscal, taxation, and other policies in Poland; the cost of additional capital that we may require and possible related restrictions on our future operating or financing flexibility; our future ability to attract strategic participants to share the costs of exploration, exploitation, development, and acquisition activities; and future plans and the financial and technical resources of strategic participants.

The forward-looking information is based on present circumstances and on our predictions respecting events that have not occurred, that may not occur, or that may occur with different consequences from those now assumed or anticipated. Actual events or results may differ materially from those discussed in the forward-looking statements as a result of various factors. The forward-looking statements included in this report are made only as of the date of this report. We disclaim any obligation to update any forward-looking statements whether as a result of new information, future events, or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Price Risk

Realized pricing for our oil production in the United States and Poland is primarily driven by the prevailing worldwide price of oil, subject to gravity and other adjustments for the actual oil sold. Historically, oil prices have been volatile and unpredictable. Price volatility relating to our oil production is expected to continue in the foreseeable future.

Substantially all of our gas in Poland is sold to PGNiG or its subsidiaries under contracts that extend for the life of each field. Prices are determined contractually and, in the case of our Roszkow, Zaniemysl, and Kleka wells, are tied to published tariffs. The tariffs are set from time to time by the public utility regulator in Poland. Although we are not directly subject to such tariffs, we have elected to link our price to these tariffs in our contracts with PGNiG. We expect that the prices we receive in the short term for gas we produce will be lower than would be the case in an unregulated setting and may be lower than prevailing western European prices. We believe it is more likely than not that, over time, the end user gas price in Poland will converge with the average price in Europe.

We currently do not engage in any hedging activities to protect ourselves against market risks associated with oil and gas price fluctuations, although we may elect to do so in the future.

Foreign Currency Risk

We enter into various agreements in Poland denominated in the Polish zloty. The Polish zloty is subject to exchange-rate fluctuations that are beyond our control. Our policy is to reduce currency risk by, under ordinary circumstances, transferring dollars to zlotys, or fixing the exchange rate for future transfers of dollars to zlotys, on or about the occasion of making any significant commitment payable in Polish currency, taking into consideration the future timing and amounts of committed costs and the estimated timing and amounts of zloty-based revenues. We do not use derivative financial instruments for trading or speculative purposes. We have used forward-purchase contracts to buy zlotys at specified exchange rates. The fair value of these contracts is estimated based on period-end quoted market prices, and the resulting asset and expense is recognized in our consolidated financial statements. As of June 30, 2011, we had no outstanding zloty forward-purchase contracts.

ITEM 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized, and reported within the time periods specified by the Securities and Exchange Commission's rules and forms, and that information is accumulated and communicated to our management, including our principal executive and principal financial officers (whom we refer to in this periodic report as our Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. Our management evaluated, with the participation of our Certifying Officers, the effectiveness of our disclosure controls and procedures as of June 30, 2011, pursuant to Rule 13a-15(b) under the Securities Exchange Act. Based upon that evaluation, our Certifying Officers concluded that, as of June 30, 2011, our disclosure controls and procedures were effective.

There were no changes in our internal control over financial reporting that occurred during our most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1A. RISK FACTORS

Information regarding risk factors appears in “Management’s Discussion and Analysis of Financial Condition and Results of Operations —Forward-Looking Statements,” in Part I — Item 2 of this Form 10-Q and in Part I — Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2010. The risks described in our Annual Report on Form 10-K for the year ended December 31, 2010, are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially and adversely affect our business, financial condition, or operating results.

ITEM 6. EXHIBITS

The following exhibits are filed as a part of this report:

Exhibit Number*	Title of Document	Location
Item 31	Rule 13a-14(a)/15d-14(a) Certifications	
31.01	Certification of Principal Executive Officer Pursuant to Rule 13a-14	Attached
31.02	Certification of Principal Financial Officer Pursuant to Rule 13a-14	Attached
Item 32	Section 1350 Certifications	
32.01	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Attached
32.02	Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Attached

* All exhibits are numbered with the number preceding the decimal indicating the applicable SEC reference number in Item 601 and the number following the decimal indicating the sequence of the particular document.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

FX ENERGY, INC.
(Registrant)

Date: August 9, 2011

By: /s/ David N. Pierce
David N. Pierce, President,
Chief Executive Officer

Date: August 9, 2011

By: /s/ Clay Newton
Clay Newton, Principal Financial Officer