BPI Energy Holdings, Inc.
Form 10-Q
March 17, 2008

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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 January 31, 2008
Commission File No. 001-32695

BPI Energy Holdings, Inc.
(Exact Name of Registrant as Specified in Its Charter)

British Columbia, Canada	**75-3183021**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
30775 Bainbridge Road, Suite 280, Solon, Ohio	**44139**
(Address of Principal Executive Offices)	(Zip Code)

Registrant s telephone number, including area code: **(440) 248-4200**

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 þ No o

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. (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer þ (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).Yes o No þ

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date: Common Shares, without par value, as of March 5, 2008: 73,611,896.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

BPI ENERGY HOLDINGS, INC.
Consolidated Balance Sheets
(Dollars in thousands)

	January 31, 2008 (Unaudited)	July 31, 2007
ASSETS		
Current Assets		
Cash and cash equivalents	$ 2,578	$ 11,292
Accounts receivable	258	94
Other current assets	1,298	1,348
Total current assets	4,134	12,734
Property and equipment, at cost:		
Gas properties, full cost method of accounting:		
Proved, net of accumulated depreciation, depletion, amortization and impairment of $12,815 and $12,621	21,936	16,631
Unproved, excluded from amortization	10,372	8,533
Support equipment, net of accumulated depreciation and amortization of $828 and $741	434	552
Net gas properties	32,742	25,716
Other property and equipment, net of accumulated depreciation and amortization of $214 and $152	457	473
Net property and equipment	33,199	26,189
Restricted cash	100	100
Other non-current assets	168	220
Total assets	$ 37,601	$ 39,243
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 1,126	$ 1,371
Current maturities of long-term debt and notes payable	10,959	8,488
Accrued liabilities and other	537	1,503
Total current liabilities	12,622	11,362
Long-term debt and notes payable, less current maturities	38	48
Asset retirement obligation	156	114
Other long-term liabilities	16	
Total liabilities	12,832	11,524
Shareholders Equity		
Common shares, no par value, authorized 200,000,000 shares, 73,611,896 and 72,524,493 issued and outstanding	67,946	67,946

Additional paid-in capital	8,250	7,608
Accumulated deficit	(51,427)	(47,835)
Total shareholders equity	24,769	27,719
Total liabilities and shareholders equity	$ 37,601	$ 39,243

See notes to unaudited consolidated financial statements

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BPI ENERGY HOLDINGS, INC.
Consolidated Statements of Operations
(Dollars in thousands, except per share data)
(Unaudited)

	Three Months Ended January 31, 2008	Three Months Ended January 31, 2007	Six Months Ended January 31, 2008	Six Months Ended January 31, 2007
Revenue				
Gas sales	$ 438	$ 247	$ 756	$ 541
Operating expenses				
Lease operating expense	377	528	635	864
General and administrative expenses	1,519	1,470	3,403	4,204
Lease rentals and other operating expense	79		79	
Depreciation, depletion and amortization	168	192	348	376
Total operating expenses	2,143	2,190	4,465	5,444
Operating loss	(1,705)	(1,943)	(3,709)	(4,903)
Other income (expense):				
Interest income	34	166	131	385
Interest expense	(30)	(3)	(32)	(6)
Other income	44		18	
	48	163	117	379
Net loss	$ (1,657)	$ (1,780)	$ (3,592)	$ (4,524)
Basic and diluted net loss per share	$ (0.02)	$ (0.03)	$ (0.05)	$ (0.07)
Weighted average common shares outstanding	71,054,872	70,059,225	70,485,748	69,427,874

See notes to unaudited consolidated financial statements

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BPI ENERGY HOLDINGS, INC.
Consolidated Statements of Shareholders Equity
(Dollars in thousands)
(Unaudited)

	Common Shares		Additional Paid-in	Accumulated	Total Shareholders
	Shares	**Amount**	**Capital**	**Deficit**	**Equity**
Balance, July 31, 2007	72,524,493	$ 67,946	$ 7,608	$ (47,835)	$ 27,719
Share-based compensation common shares (number of shares include non-vested portion of restricted stock)	1,863,735		671		671
Shares forfeited	(431,666)				
Surrender of shares to pay taxes	(344,666)		(29)		(29)
Net loss				(3,592)	(3,592)
Balance, January 31, 2008	73,611,896	$ 67,946	$ 8,250	$ (51,427)	$ 24,769

See notes to unaudited consolidated financial statements

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BPI ENERGY HOLDINGS, INC.
Consolidated Statements of Cash Flows
(Dollars in thousands)
(Unaudited)

	Six Months Ended January 31,	
	2008	**2007**
Cash Provided by (Used in):		
Operating Activities		
Net loss	$ (3,592)	$ (4,524)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation, depletion, and amortization	348	376
Share-based payments	671	834
Loss on fair value of commodity derivative contract	16	
Accretion of asset retirement obligation	4	3
Changes in assets and liabilities:		
Accounts receivable	(164)	12
Other current assets	(35)	(279)
Accounts payable	57	(14)
Accrued liabilities and other	(966)	(565)
Other assets and liabilities	52	
Net cash used in operating activities	(3,609)	(4,157)
Investing Activities		
Additions to property and equipment	(6,658)	(4,746)
Net cash used in investing activities	(6,658)	(4,746)
Financing Activities		
Proceeds from issuance of debt	1,721	
Payments on long-term debt and notes payable	(12)	(120)
Payment of deferred financing costs	(127)	
Payments for surrender of shares	(29)	
Net cash provided by (used in) financing activities	1,553	(120)
Net decrease in cash and cash equivalents	(8,714)	(9,023)
Cash and cash equivalents at the beginning of the year	11,292	19,279
Cash and cash equivalents at the end of the period	$ 2,578	$ 10,256
Supplementary disclosure of cash flow information:		
Interest paid (net of interest capitalized)	$ 30	$ 4
Non-cash financing activity interest paid-in-kind (added to debt principal)	$ 596	$

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BPI ENERGY HOLDINGS, INC.
Notes to Consolidated Financial Statements
Unaudited
(Dollars in thousands)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These unaudited consolidated interim financial statements include the accounts of BPI Energy Holdings, Inc. and its wholly owned U.S. subsidiary, BPI Energy, Inc. (collectively, the Company). All inter-company transactions and balances have been eliminated upon consolidation.

BPI Energy Holdings, Inc. is incorporated in British Columbia, Canada and, through its wholly owned U.S. subsidiary, BPI Energy, Inc. (BPI Energy), is involved in the exploration, production and commercial sale of coalbed methane (CBM) located in the Illinois Basin. The Company conducts its operations in one reportable segment, which is gas exploration and production. The Company s common shares trade on the American Stock Exchange under the symbol BPG. Dollar amounts shown are in thousands of U.S. Dollars, except for per share and per unit amounts and unless otherwise indicated.

The accompanying unaudited consolidated financial statements have been prepared in accordance with generally accepted accounting principles for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the three and six months ended January 31, 2008 are not necessarily indicative of the results that may be expected for the full fiscal year. For further information, refer to the consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the fiscal year ended July 31, 2007. Certain prior period amounts have been reclassified to conform to the current period s presentation.

Going Concern

These unaudited consolidated financial statements have been prepared on the basis of accounting principles applicable to a going concern, which contemplates the Company s ability to realize its assets and discharge its liabilities in the normal course of business. The Company has experienced significant losses in recent periods and has an accumulated deficit of $51,427 at January 31, 2008. In addition, the Company has a cash balance of only $2,578 and has negative working capital as of January 31, 2008. The Company is not currently drilling new wells; however, based on its current working capital situation, the Company needs to raise cash in order to be able to settle its accounts payable and fund its net cash used in operating activities through the fiscal quarter ended April 30, 2008. Net cash used in operating activities was ($2,219) during the first quarter of fiscal year 2008 and ($1,390) during the second quarter of fiscal year 2008 for a total of ($3,609) during the first six months of fiscal year 2008. In order to continue as a going concern, the Company must be able to not only finance its current operations but also to pay amounts due under its Advancing Term Credit Agreement with GasRock Capital LLC, as amended (the Credit Agreement), when due on January 30, 2009, and finance any future exploration and development costs.

The Company has historically financed its activities primarily from the proceeds of private placements of its common shares and most recently from advances under the Credit Agreement as discussed in Note 6. The Company is currently evaluating what options are available to finance current and future operations and engaging in discussions with potential funding sources and transaction partners. The Company engaged Tristone Capital (U.S.A.), Inc. to assist in evaluating its potential options, which include additional advances under its Credit Agreement, which are at the discretion of GasRock, issuance of new debt and/or equity securities, joint ventures, mergers/combinations, asset sales or a combination of these alternatives. Although the Company is currently evaluating its options and engaging in discussions with potential funding sources and transaction partners to raise the necessary funds, it can provide no assurance that it will be successful in completing a financing or transaction. Failure to raise adequate funds in the near term would have a material adverse effect on the Company.

Use of Estimates

The preparation of these unaudited consolidated financial statements requires the use of certain estimates by management in determining the Company s assets, liabilities, revenues and expenses. Actual results could differ from such estimates. Depreciation, depletion and amortization of gas properties and the impairment of gas properties are determined using estimates of gas reserves. There are numerous uncertainties in estimating the quantity of reserves and in projecting the future rates of production and timing of development expenditures, including the timing and costs associated with the Company s asset retirement obligations. Gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of gas that cannot be measured in an exact way. Proved reserves of gas are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions.

Accounts Receivable

Accounts receivable at January 31, 2008 represent amounts due from GasRock in accordance with the terms of the Credit Agreement under which GasRock receives directly all proceeds from the Company s gas sales and then reimburses the Company for eligible operating expenses, as defined under the Credit Agreement. Accounts receivable at July 31, 2007 represent amounts due from Atmos Energy Marketing, LLC for gas sales. Management regularly reviews accounts receivable to determine whether amounts are collectible and records a valuation allowance to reflect management s best estimate of any amount that may not be collectible. At January 31, 2008 and July 31, 2007, the Company has determined that no allowance for uncollectible receivables was necessary.

Deferred Financing Costs

The Company capitalizes costs incurred in connection with borrowings or establishment of credit facilities. These costs are amortized as an adjustment to interest expense over the life of the borrowing or life of the credit facility using the interest method. In the case of early debt principal repayments, the Company adjusts the value of the corresponding deferred financing costs with a charge to other expense, and similarly adjusts the future amortization expense. The Company recorded approximately $127 and $212 of non-cash amortization expense related to deferred financing costs during the three months and six months ended January 31, 2008, respectively. The amortization was included as interest expense subject to capitalization as unproved gas properties during the three and six months ended January 31, 2008.

Commodity Derivatives

The Company accounts for derivative instruments or hedging activities under the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities. SFAS No. 133 requires the Company to record derivative instruments at their fair value.

Under the terms of the Company s Credit Agreement with GasRock, the Company is required to enter into derivative contracts covering approximately 75% of its proved developed producing reserves scheduled to be produced during a two-year period at a guaranteed price of not less than $7.00 per one million of British thermal units (MMBtu). The objective is to reduce the Company s exposure to commodity price risk associated with expected gas production.

The Company s risk management strategy is to enter into commodity derivatives that set price floors and price ceilings for its natural gas production. On July 31, 2007, the Company entered into a costless collar contract with BP Corporation North America Inc. (BP) for the notional amount of 20,000 MMBtus per month beginning September 1, 2007 through July 31, 2009 (460,000 MMBtus in total). Under the terms of the contract, BP is required to cover any shortfall below the floor of $7.00 per MMBtu and the Company must pay to BP any amounts above the ceiling of $11.00 per MMBtu as to the notional amount, with the price being based on the second to last close of the NYMEX (New York Mercantile Exchange) forward price for each month. The Company expects that it will enter into additional derivative contracts during the next two years to cover the entire 75% of its proved developed producing reserves scheduled to be produced during that period.

The Company has elected not to designate its commodity derivative as a hedge, and accordingly, such contract is recorded at fair value on its consolidated balance sheets and changes in such fair value are recognized in current earnings as other income or expense as they occur. As of October 31, 2007, the fair value of the contract with BP was estimated to be approximately $16, in a net liability position and such amount has been recorded as a non-current liability in the January 31, 2008 unaudited consolidated balance sheet. In addition, the change in fair value of $44 and $(60) during the three and six months ended January 31, 2008, respectively, has been recorded as other income (expense) in the unaudited consolidated statements of operations.

The Company does not hold or issue commodity derivatives for speculative or trading purposes. The Company is exposed to credit losses in the event of nonperformance by the counterparty to its commodity derivative. It is anticipated, however, that its counterparty, BP, will be able to fully satisfy its obligations under the commodity derivative contract. The Company does not obtain collateral or other security to support its commodity derivative contract subject to credit risk but does monitor the credit standing of the counterparty.

Realized gains or losses from the settlement of gas derivative contracts are reported as other income or expense on the consolidated statements of operations. On July 31, 2007, the Company entered into the first commodity derivative contract with the first settlement month designated as September 2007. The Company recorded net realized gains on settlement of its derivative contract of $0 and approximately $41 during the three and six months ended January 31, 2008, respectively. Such amounts are included as other income in the unaudited consolidated statements of operations.

Capitalized Interest

The Company capitalizes interest costs to gas properties on expenditures made in connection with unproved properties that are not subject to current depletion. Interest is capitalized only for the period during which activities are in progress to bring these properties to their intended use. Total interest expense incurred during the three months and six months ended January 31, 2008, including the amortization of deferred financing costs and debt discount, was approximately $613 and $1,115. Of these amounts, interest costs capitalized to unproved gas properties during the three and six months ended January 31, 2008 was approximately $583 and $1,083, respectively. No interest costs were capitalized in prior periods.

Gas Properties

The Company follows the full cost method of accounting for gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of gas reserves are capitalized in cost centers on a country-by-country basis (currently the Company has one cost center, the United States). Such costs include lease acquisition costs, geological and geophysical studies, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, and overhead expenses directly related to these activities. Internal costs associated with gas activities that are directly attributable to acquisition, exploration or development activities are capitalized as properties and equipment on the balance sheet. The Company capitalized internal labor and benefit costs determined to be directly attributable to acquisition, exploration or development activities in the amount of $77 and $201 during the three and six months ended January 31, 2008, respectively, and $92 and $230 during the three and six months ended January 31, 2007, respectively. Costs associated with production and general corporate activities are expensed in the period incurred.

A ceiling test is applied to each cost center by comparing the net capitalized costs, less related deferred income taxes, to the estimated future net revenues from production of proved reserves, discounted at 10%, plus the costs of unproved properties net of impairment. Any excess capitalized costs are written-off in the current year. The calculation of future net revenues is based upon prices, costs and regulations in effect at each period-end. At January 31, 2008, the carrying amount of net gas properties was less than the full cost ceiling limitation based on an January 31, 2008 Henry Hub gas price of $8.10 per MMBtu, and, therefore, no ceiling cost write-down was recognized.

Capitalized costs of proved gas properties, including estimated future costs to develop the reserves and estimated abandonment cost, net of salvage, are amortized on the units-of-production method using estimates of proved reserves. Support equipment represents vehicles and other mobile equipment used in gas operations and is depreciated using the straight-line method over the estimated useful lives of the assets, ranging from three to five years.

Unproved gas properties and major development projects are excluded from amortization until a determination of whether proved reserves can be assigned to the properties or impairment occurs. Unproved properties are assessed at least annually to ascertain whether an impairment has occurred. Sales or dispositions of properties are credited to their respective cost centers and a gain or loss is recognized when all the properties in a cost center have been disposed of, unless such sale or disposition significantly alters the relationship between capitalized costs and proved reserves attributable to the cost center.

In general, the Company determines if an unproved property is impaired if one or more of the following conditions exist:

i) there are no firm plans for further drilling on the unproved property;

ii) negative results were obtained from studies of the unproved property;

iii) negative results were obtained from studies conducted in the vicinity of the unproved property; or

iv) the remaining term of the unproved property does not allow sufficient time for further studies or drilling.

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No impairment of unproved properties existed as of January 31, 2008 or July 31, 2007.

Other Property and Equipment

Other property and equipment is stated at cost, net of depreciation and amortization, and includes fixed assets such as office equipment, computer hardware and software, and furniture and fixtures and is depreciated using the straight-line method over the estimated useful lives of the assets, ranging from three to five years.

Income Taxes

Income taxes are accounted for under the asset and liability method that requires deferred income taxes to reflect the future tax consequences attributable to differences between the tax and financial reporting bases of assets and liabilities. Deferred tax assets and liabilities recognized are based on the tax rates in effect in the year in which differences are expected to reverse. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management based on available evidence, it is more likely than not that some or all of any net deferred tax assets will not be realized.

The Company adopted the provisions of Financial Accounting Standards Board (FASB) Interpretation No. 48, Accounting for Uncertainty in Income Taxes An interpretation of FASB Statement No. 109 (FIN 48) on August 1, 2007. The adoption of FIN 48 had no effect on the Company s unaudited interim financial statements as of and for the three and six months ended January 31, 2008.

The Company s policy is to recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as operating expenses. The Company was not subject to any such interest or penalties during the three and six months ended January 31, 2008 and 2007, respectively.

Loss Per Share

Basic loss per share is calculated using the weighted average number of common shares outstanding during the period. Diluted loss per share reflects the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted into common shares. Restricted common shares granted are included in the computation only after the shares become fully vested. Diluted loss per share is not disclosed as it is anti-dilutive. The following items were excluded from the computation of diluted loss per share at January 31, 2008 and 2007, respectively, as the effect of their assumed exercises or vesting would be anti-dilutive:

	January 31, 2008	**January 31, 2007**
Outstanding warrants	1,037,200	5,311,600
Outstanding stock options	1,579,931	1,529,931
Nonvested portion of restricted shares issued	2,043,438	2,537,338
	4,660,569	9,378,869

Recently Issued Accounting Standards

In June 2006, the FASB issued FIN 48. This Interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. This Interpretation is effective for fiscal years beginning after December 15, 2006. As discussed above, the Company adopted FIN 48 on August 1, 2007. The adoption of FIN 48 by the Company had no effect on its consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. The standard provides guidance for using fair value to measure assets and liabilities. Under the standard, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. The standard clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, the standard establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The statement is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. Therefore, the Company will need to comply with SFAS No. 157 beginning in the fiscal year

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ending July 31, 2009. The Company is currently evaluating the statement to determine what impact, if any, it will have on its consolidated financial statements.

During February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115. The standard permits an entity to make an irrevocable election to measure most financial assets and financial liabilities at fair value. The fair value option may be elected on an instrument-by-instrument basis, with a few exceptions, as long as it is applied to the instrument in its entirety. Changes in fair value would be recorded in income. SFAS No. 159 establishes presentation and disclosure requirements intended to help financial statement users understand the effect of the entity s election on earnings. SFAS No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007. Therefore, the Company will need to comply with SFAS No. 159 beginning in the fiscal year ending July 31, 2009. Early adoption is permitted. The Company is currently evaluating the statement to determine what impact, if any, it will have on its consolidated financial statements.

2. SHARE-BASED COMPENSATION

SFAS No. 123(R)

The Company follows the provisions of SFAS No. 123(R), Share-Based Payment. SFAS No. 123(R) focuses primarily on the accounting for transactions in which an entity obtains employee services in share-based payment transactions. The key provision of SFAS No. 123(R) requires companies to record share-based payment transactions as expense at fair market value based on the grant-date fair value of those awards. The company s share-based compensation expense represents the cost related to share-based awards granted to employees and directors. The Company measures share-based compensation expense at grant date, based on the estimated fair value of the award, and recognizes the cost as expense on a straight-line basis (net of estimated forfeitures) over the requisite service period. The Company uses the Black-Scholes valuation model to estimate the fair value of stock options granted.

Incentive Stock Option Plan

Prior to December 13, 2005, the Company administered a share-based compensation plan (the Incentive Stock Option Plan) under which stock options were issued to directors, officers, employees and consultants as determined by the Board of Directors and subject to the provisions of the Incentive Stock Option Plan. The Incentive Stock Option Plan permitted options to be issued with exercise prices at a discount to the market price of the Company s common shares on the day prior to the date of grant. However, the majority of all stock options issued under the Incentive Stock Option Plan were issued with exercise prices equal to the quoted market price of the stock on the date of grant. Options granted under the Incentive Stock Option Plan vested immediately and were exercisable over a period not exceeding five years.

Omnibus Stock Plan

On December 18, 2006, the Company s shareholders approved the Amended and Restated 2005 Omnibus Stock Plan (the Omnibus Stock Plan), which the Company s shareholders had originally approved on December 13, 2005. The Omnibus Stock Plan replaces the Incentive Stock Option Plan under which stock options were previously granted. The Omnibus Stock Plan is administered by the Compensation Committee of the Board of Directors (the Committee) and will remain in effect until December 13, 2010. All employees and directors of the Company and its subsidiaries, and all consultants or agents of the Company designated by the Committee, are eligible to participate in the Omnibus Stock Plan. The Committee has authority to: grant awards; select the participants who will receive awards; determine the terms, conditions, vesting periods and restrictions applicable to the awards; determine how the exercise price is to be paid; modify or replace outstanding awards within the limits of the Omnibus Stock Plan; accelerate the date on which awards become exercisable; waive the restrictions and conditions applicable to awards; and establish rules governing the Omnibus Stock Plan.

The Omnibus Stock Plan provides that in any fiscal year of the plan the Company may grant awards up to 5% of the number of common shares outstanding as of the first day of that fiscal year plus the number of common shares that were available for the grant of awards, but not granted, in prior years under the plan. In no event, however, may the number of common shares available for the grant of awards in any fiscal year exceed 6% of the common shares outstanding as of the first day of that fiscal year. In addition, the aggregate number of common shares that could be issued under the Omnibus Stock Plan is capped at 7,000,000. As of January 31, 2008, the Company has issued 50,000 stock options, 3,557,109 restricted common shares and 1,227,626 fully vested common shares under the Omnibus Stock Plan, and there are 2,165,265 awards available for future issuance under the Plan. Stock options granted

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under the Omnibus Stock Plan were granted with exercise prices denominated in U.S. Dollars equal to the quoted market price of the Company s common shares on the date of grant and were fully vested on the date of grant.
The following table summarizes information about the options outstanding at January 31, 2008:

Exercise Price	Number Outstanding	Remaining Life (Years)	Expiry Date
$ 0.49	345,000	0.8	November 3, 2008
0.70	10,000	1.6	September 22, 2009
0.83	50,000	4.4	June 7, 2012
1.26	695,666	1.8	November 29, 2009
1.75	10,000	2.6	September 23, 2010
1.80	136,000	2.2	March 27, 2010
1.95	333,265	2.0	January 20, 2010
$ 1.27	1,579,931	1.7	

All outstanding options are fully vested at January 31, 2008. The intrinsic value of outstanding options is $0 at January 31, 2008.
A summary of the status of the Company s nonvested restricted shares as of January 31, 2008 and changes during the three and six months ended January 31, 2008 is as follows:

Nonvested Shares	Shares	Weighted Average Grant-Date Fair Value
Nonvested at July 31, 2007	2,437,338	$ 0.71
Granted	1,024,770	0.55
Vested	(350,000)	0.93
Forfeited	(259,000)	0.50
Nonvested at October 31, 2007	2,853,108	$ 0.64
Granted	10,000	0.35
Vested	(647,004)	0.52
Forfeited	(172,666)	0.87
Nonvested at January 31, 2008	2,043,438	$ 0.66

During the three and six months ended January 31, 2008, the Committee granted share awards under the Omnibus Stock Plan in the form of restricted and unrestricted shares to employees and directors as follows:

	Restricted Shares	Fully Vested Shares	Total Shares
Three Months Ended October 31, 2007:			
Employee bonuses	754,500	512,500	1,267,000
Directors fees	270,270		270,270
	1,024,770	512,500	1,537,270
Three Months Ended January 31, 2008:			
Employee bonuses	10,000		10,000

Directors fees		316,465	316,465
	10,000	316,465	316,465
Total number of shares granted	1,034,770	828,965	1,863,735

Employee Bonuses

On August 2, 2007, the Company granted 754,500 restricted shares and 512,500 fully vested common shares to employees for performance bonuses related to the fiscal year ended July 31, 2007. The restrictions on the restricted shares will lapse based on service two years from the date of grant and the related expense will be recognized on a straight-line basis over the requisite service period of the employees. The expense related to the fully vested shares was recognized during the fiscal year ended July 31, 2007. On January 31, 2008, the Company granted 10,000 restricted shares to a newly hired employee as a signing bonus. The restrictions on these shares will lapse evenly over a three-year period from the date of grant and the related expense will be recognized on a straight-line basis over the requisite service period of the employee.

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Directors Fees

On October 31, 2007, the Company granted 270,270 restricted shares to a new director. The restrictions on these shares will lapse evenly over a three-year period from the date of grant subject to the director standing for re-election in the year the shares are scheduled to vest. The related expense will be recognized on a straight-line basis over the requisite service period of the director.

On January 15, 2008, the Company granted 316,465 fully vested common shares to certain directors who elected to have their cash compensation converted into the Company s common shares for fees earned for their attendance at Board and Committee meetings during fiscal 2007. The expense related to these fully vested shares was recognized as share-based compensation expense during the periods incurred.

The Omnibus Stock Plan allows participants to surrender common shares to satisfy the Company s tax withholding obligations related to the vesting of shares. During the three and six months ended January 31, 2008, employees surrendered 183,999 and 344,666 shares, respectively, to satisfy tax withholding obligations totaling $108 and $123, respectively. Of these amounts, $94 was paid during the fiscal year ended July 31, 2007. The amount paid by the Company for withholding taxes related to shares surrendered is recorded as a decrease to additional paid-in capital in the period such taxes are paid.

All restricted share awards are subject to continuous employment. However, in the event employment is terminated before the restrictions lapse by reason of death, total disability or retirement, the restrictions will lapse on the date of termination as to a pro rata portion of the number of restricted shares scheduled to vest on the next vesting date, based on the number of days continuously employed during the applicable vesting period. The Company includes all restricted shares in common shares outstanding when issued, but only includes the vested portion of such shares in the computation of basic earnings per share.

The Company s policy is to issue new shares to satisfy stock option exercises and restricted share grants upon receiving approval from the American Stock Exchange, when required, for the issuance of such shares.

As of January 31, 2008, there was approximately $992 of unrecognized compensation cost related to restricted shares. The cost is expected to be amortized over a weighted average period of 1.1 years. The amount charged to expense related to the pro rata vesting of restricted shares was $212 and $478 during the three and six months ended January 31, 2008, respectively, and $232 and $507 during the three and six months ended January 31, 2007, respectively.

3. OTHER CURRENT ASSETS

Other current assets consisted of the following at January 31, 2008 and July 31, 2007, respectively:

	January 31, 2008	July 31, 2007
Deferred financing costs	$ 751	$ 836
Separation agreement costs	206	322
Prepaid expenses and other	341	190
	$ 1,298	$ 1,348

Deferred financing costs consist of investment banking fees, legal fees and other fees and expenses incurred directly in connection with the establishment of the Company s Credit Agreement with GasRock. These costs are being amortized as an adjustment to interest expense over the life of the Credit Agreement using the interest method. The Company incurred approximately $122 and $127 additional deferred financing costs and recorded approximately $127 and $212 of amortization expense related to deferred financing costs during the three and six months ended January 31, 2008, respectively.

Separation agreement costs represent unamortized costs associated with a Separation Agreement and Waiver and Release (Separation Agreement) with a former officer and director of the Company entered into on October 12, 2006. Under the terms of the Separation Agreement, the Company agreed to provide consideration to the former officer and director upon his resignation for severance, consulting services and his agreement not to compete or solicit the

Company s employees. The Company capitalized the value of the expected future benefit to be received from both the consulting services and the non-compete/non-solicitation agreement and is amortizing the related expense ratably over the future periods in which it expects to receive the related benefits. As of January 31, 2008, $206 of unamortized value related to the consulting services and the non-compete/non-solicitation agreement are recorded as an other current asset on the balance sheet, representing the amount to be amortized over the next year. The Company recognized

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expense in connection with the Separation Agreement in the amount of $85 and $175 during the three and six months ended January 31, 2008, respectively, and $90 and $109 during the three and six months ended January 31, 2007, respectively.

4. OTHER NON-CURRENT ASSETS

Other non-current assets consisted of the following at January 31, 2008 and July 31, 2007, respectively:

	January 31, 2008	July 31, 2007
Separation Agreement	$	$ 59
Advance royalties	168	161
	$ 168	$ 220

5. ACCRUED LIABILITIES

Accrued liabilities consisted of the following at January 31, 2008 and July 31, 2007, respectively:

	January 31, 2008	July 31, 2007
Professional fees	$ 354	$ 133
Employee compensation	183	1,112
Separation agreement		100
Directors fees		57
Other		101
	$ 537	$ 1,503

6. LONG-TERM DEBT AND NOTES PAYABLE

On July 27, 2007, the Company entered into a Credit Agreement with GasRock. The Credit Agreement provides for an initial commitment to the Company of $10,200 and the possibility of future advances to the Company of up to an additional $64,800. All future advances under the Credit Agreement beyond the initial commitment will be made in GasRock s discretion. Under the original terms of the Credit Agreement, the Company could request advances under the Credit Agreement at any time before July 25, 2008, which GasRock could, at its discretion, extend until July 27, 2010. All amounts then outstanding under the original terms of the Credit Agreement were due and payable on July 25, 2008, which GasRock could, at its discretion, extend until July 29, 2011. On November 29, 2007, the Company entered into an amendment to the Credit Agreement that extended the date until which the Company may request advances under the Credit Agreement, and the date upon which all amounts outstanding under the Credit Agreement will be due and payable, from July 25, 2008 to January 30, 2009 (the Loan Termination Date). The date to which GasRock may, at its option, extend the Credit Agreement was also extended from July 29, 2011 to January 30, 2013. The amendment also increased the initial commitment under the Credit Agreement from $10,200 to $10,700. The Company has received advances totaling $10,781 under the Credit Agreement, resulting in net cash proceeds to the Company of $9,818 after the deduction of GasRock s facility fees, investment banking fees, legal fees and other fees and expenses incurred by the Company in connection with the Credit Agreement totaling $963. The Company has capitalized such fees and expenses incurred in connection with the Credit Agreement as a deferred charge (asset) that is being amortized over the initial term of the Credit Agreement using the interest method.

For the term of the Credit Agreement ending on the Loan Termination Date, all amounts outstanding under the Credit Agreement will bear interest at a rate equal to the greater of (i) 15% per annum and (ii) the LIBOR rate plus 9% per annum. If GasRock extends the Loan Termination Date, amounts outstanding under the Credit Agreement will thereafter bear interest at a rate equal to the greater of (i) 12% per annum and (ii) the LIBOR rate plus 6% per annum. The Company is required to make monthly interest payments on the amounts outstanding under the Credit Agreement based on available funds existing after deducting all monthly operating expenses of the Company s wells from monthly revenue, as defined by the Credit Agreement. Any accrued but unpaid interest due each month during the first year of the term of the Credit Agreement is included in the principal amount of the loan. As of January 31, 2008, approximately $596 of interest incurred to date has been added to the principal amount of the loan. The Company is not required to make any principal payments until the Loan Termination Date. The Company may prepay the amounts outstanding under the Credit Agreement at any time without penalty.

The Company is required to pay GasRock a facility fee upon the receipt of any advances under the Credit Agreement in an amount equal to 2% of the amount advanced. The Company is also required to reimburse GasRock for all of the expenses incurred by GasRock in connection with entering into and administering the Credit Agreement. The facility fee related to the initial advance and

GasRock s expenses in connection with entering into the Credit Agreement were included in the principal amount of the initial advance.

The Company s obligations under the Credit Agreement are secured by a first priority security interest in substantially all of the Company s properties and assets, including all of the Company s CBM rights under its leases, farm-out agreements and fee interests, all of the Company s wells at its Southern Illinois Basin Project, all of the Company s equipment, and all of the common stock of BPI Energy. A guaranty of all of BPI Energy s obligations under the Credit Agreement was provided by BPI Energy Holdings, Inc.

In connection with the execution of the Credit Agreement, the Company granted GasRock a 1% royalty in all CBM produced and saved from the Company s existing leased and owned CBM properties and an additional 4% royalty interest in all CBM produced and saved from the Company s existing wells at its Southern Illinois Basin Project. As long as any of the Company s obligations remain outstanding under the Credit Agreement, the Company will be required to grant the same 1% royalty interest to GasRock on new mineral interests acquired by the Company and the same 4% royalty interest on new wells drilled by the Company that are funded by draws under the Credit Agreement. The Company estimated the fair value of the royalty interests granted to GasRock to be approximately $600 and recorded this amount as a debt discount. The debt discount is being amortized as an adjustment to interest expense over the life of the loan using the interest method. The Company recorded approximately $90 and $151 of non-cash amortization expense related to the debt discount during the three and six months ended January 31, 2008, respectively. The amortization was included as interest expense subject to capitalization as unproved gas properties during the three months and six months ended January 31, 2008. The unamortized amount of the debt discount of $600 and $449 at January 31, 2008 and July 31, 2007, respectively, is deducted directly from long-term debt reflected in the unaudited consolidated balance sheets as of each period-end.

BPI Energy is subject to various restrictive covenants under the Credit Agreement, including limitations on its ability to sell properties and assets, make distributions, extend credit, amend its material contracts, incur indebtedness, provide guarantees, effect mergers or acquisitions, cancel claims, create liens, create subsidiaries, amend its formation documents, make investments, enter into transactions with its affiliates, and enter into swap agreements. BPI Energy must maintain (i) a current ratio of at least 1.0 (excluding from the calculation of current liabilities any advances outstanding under the Credit Agreement) and (ii) a loan-to-value ratio greater than 1.0 to 1.0 for the period commencing on September 30, 2008 and ending on March 31, 2010 and 0.7 to 1.0 thereafter. The Company is in compliance with its debt covenants as of January 31, 2008.

The Credit Agreement contains customary events of default. In addition, GasRock may declare an event of default if, at any time after July 25, 2008, the Company s most recent reserve report indicates that (i) the Company s projected net revenue attributable to its proved reserves is insufficient to fully amortize the amounts outstanding under the Credit Agreement within a 48-month period and (ii) the Company is unable to demonstrate to GasRock s reasonable satisfaction that the Company would be able to satisfy such outstanding amounts through a sale of the Company s assets or equity. Upon the occurrence of an event of default under the Credit Agreement, GasRock may accelerate the Company s obligations under the Credit Agreement. Upon certain events of bankruptcy, the Company s obligations under the Credit Agreement would automatically accelerate. In addition, at any time that an event of default exists under the Credit Agreement, the Company will be required to pay interest on all amounts outstanding under the Credit Agreement at a default rate, which is equal to the then-prevailing interest rate under the Credit Agreement plus 4% per annum.

In addition to the loans outstanding under the GasRock credit facility, the Company has outstanding term notes payable related to vehicles and equipment. The term notes are collateralized by the related vehicles and equipment. Following is a summary of all long-term debt and notes payable outstanding at January 31, 2008 and July 31, 2007:

	January 31, 2008	**July 31, 2007**
Advances under GasRock Credit Agreement	$ 11,382	$ 9,060
GMAC term note due in fiscal year 2009, 6.50%	11	14
GMAC term notes due in fiscal year 2010, 6.1% to 6.50%	53	62

		11,446		9,136
Less unamortized debt discount		(449)		(600)
Less current maturities		(10,959)		(8,488)
Long-term debt and notes payable	$	38	$	48

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The annual principal maturities of advances under the GasRock Credit Agreement and the long-term notes payable for periods subsequent to January 31, 2008 are as follows:

Remaining Fiscal Year 2008	$ 16
Fiscal Year 2009	11,412
Fiscal Year 2010	18
	$ 11,446

7. ASSET RETIREMENT OBLIGATIONS

The Company follows SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires the Company to record the fair value of an asset retirement obligation as a liability in the period in which it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement costs is capitalized as part of the carrying amount of the associated long-lived asset. Amortization of the capitalized asset retirement cost is computed on a units-of-production method. Accretion of the asset retirement obligation is recognized over time until the obligation is settled. The Company s asset retirement obligations relate to the plugging of wells upon exhaustion of gas reserves.

The following table summarizes the activity for the Company s asset retirement obligations for the six months ended January 31, 2008 and 2007, respectively:

	Six Months Ended January 31,	
	2008	**2007**
Beginning asset retirement obligation	$ 114	$ 71
Additional liability incurred	17	7
Accretion expense	4	3
Change in estimate	33	35
Asset retirement costs incurred	(58)	(36)
Loss on settlement of liability	46	17
	$ 156	$ 97

8. CONCENTRATIONS

Financial instruments that potentially subject the Company to concentrations of credit risk consist of cash and cash equivalents, which are held at one large high quality financial institution. The Company periodically evaluates the credit worthiness of the financial institution. The Company has not incurred any credit risk losses related to its cash and cash equivalents.

The Company utilizes a limited number of drilling contractors to perform all of the drilling on its projects. The Company maintains a limited number of supervisory and field personnel to oversee drilling and production operations. The Company s plans to drill additional wells are determined in large part by the anticipated availability of acceptable drilling equipment and crews. The Company does not currently have any contractual commitments ensuring that it will have adequate drilling equipment or crews to achieve its drilling plans. The Company believes that it can secure the necessary commitments from drilling companies as required. However, it can provide no assurance that its expectations regarding the availability of drilling equipment and crews from these companies will be met. A significant delay in securing the necessary drilling equipment and crews could cause a delay in production and sales, which would affect operating results adversely.

9. INCOME TAXES

The Company files income tax returns in the U.S. federal jurisdiction, in Canada and in the State of Illinois. Primarily as a result of the net operating losses that the Company has generated, the Company has substantial net operating loss carryforwards (NOL Carryforwards) in all tax jurisdictions in which it files, none of which have been recognized for financial statement purposes. These NOL Carryforwards and other deferred tax benefits generated by the Company are available for tax purposes to offset net income in future periods. Although the Company has never been audited by any taxing authority, when and if the Company uses its NOL Carryforwards, they will be subject to audit and potential adjustment by the respective taxing authority. FASB Statement No. 109, Accounting for Income Taxes, requires that the Company record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of sufficient future taxable income before the expiration of the NOL Carryforwards. Because of the Company s limited operating history, limited financial performance and cumulative tax loss from inception, it is management s judgment that SFAS No.

109 requires the recording of a full valuation allowance for net deferred tax assets in both Canada and the United States as of January 31, 2008.

10. SHAREHOLDERS EQUITY

Common shares The Company has authorized 200,000,000 shares without par value, of which 73,611,896 and 72,524,493 were issued and outstanding as of January 31, 2008 and July 31, 2007, respectively. Shares issued and outstanding at January 31, 2008 and July 31, 2007 include 2,043,438 and 2,437,338 restricted shares, respectively, expected to vest in future periods.

Additional paid-in capital Amounts recorded of $7,957 and $8,250 at January 31, 2008 and July 31, 2007, respectively, represent the cumulative amounts of share-based compensation as of the end of each period.

Share purchase warrants During fiscal year 2005, the Company issued 10,372,000 shares at $1.25 per share with 5,186,000 share purchase warrants exercisable at $1.50 for a period of two years (Investor Warrants). The Company s agent received a commission of 5% and 1,037,200 broker warrants exercisable at $1.25 for a period of two years (Agent Warrants). The shares and warrants, when issued, were restricted under the Securities Act of 1933, as amended, and the Company was required to register the resale of the shares and the shares underlying the warrants with the Securities and Exchange Commission. Upon registration of the shares underlying the warrants and the delisting of such shares from the TSX Venture Exchange, the Investor Warrants were extended to be exercisable for two years after such listing and the Agent Warrants were extended to be exercisable for five years after the closing of the share placement. The Investor Warrants expired on December 13, 2007. Share purchase warrants outstanding at January 31, 2008 are as follows:

Number Outstanding	Exercise Price	Expiry Date
643,200	$1.25	December 31, 2009
394,000	$1.25	January 12, 2010
1,037,200		

11. RELATED PARTY TRANSACTIONS

The Company enters into various transactions with related parties in the normal course of business operations.

Randy Oestreich, the Company s Vice President of Field Operations, owns and operates A-Strike Consulting, a consulting company that provides, among other things, laboratory testing related to CBM. The Company owns and maintains a lab testing facility and allows A-Strike Consulting to operate the facility. The Company pays all expenses related to the facility and, in return, receives 80% of the revenue generated from the operations of the facility as reimbursement of the Company s expenses. The Company did not receive any expense reimbursement related to this arrangement during the six months ended January 31, 2008 or 2007.

David Preng, a director of the Company, is an owner of Preng & Associates, an executive search firm specializing in the energy and natural resources industries. The Company paid Preng & Associates $0 and approximately $10 for executive placement services during the six months ended January 31, 2008 and 2007, respectively.

12. LEGAL PROCEEDINGS

Drummond Coal Co. Litigation

Approximately 115,000 acres of CBM rights of BPI Energy, Inc. (BPI) that are located at the Northern Illinois Basin Project are currently subject to litigation. To date, BPI has drilled one well on this acreage, a test well that was drilled in September 2006.

In 2004, BPI and affiliates of the Drummond Coal Co. (Drummond), including IEC (Montgomery), LLC (IEC), entered into a letter of intent to obtain coal and CBM gas rights for one another in the Illinois Basin and to work together in a relationship in which BPI would produce CBM from coal beds prior to the Drummond affiliates mining of coal from those beds. Pursuant to and in reliance upon this letter of intent and its relationship with Drummond, BPI arranged for the transfer of 163,109 acres of coal rights to the Drummond affiliates for a total purchase price of $5,845, which BPI believes reflects a significant discount to current market prices. In light of its obligations to

Drummond, BPI charged no profit on its transfer of the coal rights to the Drummond affiliates.

Rather, in consideration for obtaining those coal rights, the Drummond affiliates were to lease approximately 115,000 acres of CBM rights to BPI for a primary lease term of 20 years and with favorable royalty rates. Although the Drummond affiliates entered into two CBM leases with BPI on April 26, 2006, they have since sought in various ways to void or terminate the leases.

Drummond affiliates IEC and Christian Coal Holdings, LLC (Christian) filed suit against BPI on February 9, 2007 in the United States District Court for the Northern District of Alabama, claiming that BPI has breached the CBM leases in various ways. On May 14, 2007, the Court granted BPI s motion to dismiss the case in its entirety on the ground of improper venue. IEC and Christian did not appeal that decision.

On March 13, 2007, BPI filed suit against IEC, Christian and additional Drummond affiliates Shelby Coal Holdings, LLC, Clinton Coal Holdings, LLC and Marion Coal Holdings, LLC in the United States District Court for the Southern District of Illinois. At the court s direction, BPI filed an amended complaint, and subsequently filed a second amended complaint that named BPI Energy Holdings, Inc. as an additional plaintiff, named Drummond Company Inc. and Drummond affiliate Vandalia Energy, LLC as additional defendants, and asserted additional claims. In its lawsuit, BPI seeks to rescind its transfers of coal rights to the Drummond affiliates for failure of consideration due to the Drummond affiliates efforts to avoid the CBM leases, has asserted claims for money damages for breach of the various agreements between the parties (including the CBM leases), breach of fiduciary duty, unjust enrichment, promissory estoppel, and tortious interference with contracts, and seeks to pierce the corporate veil to recover from Drummond and IEC for the actions of the other Drummond affiliates. The parties are currently engaged in written discovery. During the course of discovery, defendants produced an additional agreement between BPI and Christian that supported an additional claim for breach of contract, and as a result, BPI recently filed a Third Amended Complaint. Defendants have moved to stay the case on the basis that the agreement contains an arbitration provision. BPI is opposing defendants efforts to stay the case and arbitrate on the basis that defendants have waived the right to arbitrate. BPI also anticipates that defendants will file a motion to dismiss the Third Amended Complaint, because they filed motions to dismiss BPI s prior complaints. The Company anticipates that if the Court denies all or part of the motion to dismiss, Drummond and its affiliates will file counterclaims against BPI for breach of the CBM leases, citing the same bases set forth in the Alabama lawsuit.

The Company believes that Drummond and its affiliates, after having received favorable coal rights in exchange for favorable CBM rights, now wish to obtain a significant windfall by seeking to renege on the CBM rights that they were obligated to grant to BPI.

If the Drummond affiliates reinstitute their claims against BPI, the Company believes that it will be successful in defending against their claims of breach. However, there can be no assurance that the Company will be successful in maintaining these acreage rights. The loss of these acreage rights would not have a material impact on the Company s financial position, results of operations or cash flows.

ICG Litigation

In November 2004, BPI entered into a farm-out agreement under which it acquired the right to develop certain CBM in Macoupin and Perry Counties in Illinois. The farm-out agreement covers 41,253 acres of CBM rights in Macoupin County and 22,997 acres of CBM rights in Perry County. The farmor was Addington Exploration, LLC, which leased the CBM rights from Meadowlark Farms, Inc. and Ayrshire Land Company. Meadowlark and Ayrshire went into bankruptcy, and ICG Natural Resources, LLC purchased their assets, including the CBM rights underlying the Addington leases. On April 9, 2007, ICG filed suit against BPI in Perry County, Illinois, in an effort to avoid the Addington leases, claiming that there was a lack of consideration at the time the leases were executed and that there is a lack of mutuality under the leases. BPI has denied ICG s claims, and is also defending on the grounds of estoppel by deed: that ICG acquired the CBM rights subject to those leases, as set forth in the deed from Ayrshire and Meadowlark to ICG, the purchase agreement between those parties, and numerous bankruptcy court filings and orders associated with the approval of the sale. BPI is also defending on the grounds that it is a bona fide purchaser of the farmout and assignment of the leases and that it expended substantial amounts to purchase and develop the leases prior to any notice or knowledge of the claims asserted by ICG. Addington was subsequently acquired by Nytis Exploration Company, LLC, which has intervened in the action. Both BPI and Addington have filed motions for summary judgment based upon estoppel by deed, and BPI has also moved for summary judgment as a bona fide purchaser. BPI recently learned that, subsequent to filing suit, ICG transferred its Perry County coal and possibly its Perry County CBM rights to Arch Minerals, which is not currently a party to the lawsuit. To date, Arch has not challenged the farm-out agreement. BPI has drilled 10 pilot wells, one water disposal well and three test wells on the acreage covered by the farm-out agreement. In February 2008, BPI shut down its Macoupin pilot and suspended development of the Perry County pilot in response to a demand by ICG that it do so until the litigation is resolved.

The Company believes that it will be successful in defending against ICG s claims; however, there can be no assurance that it will be successful in retaining the acreage under this farm-out agreement. The loss of these acreage rights would not have a material impact on the Company s financial position, results of operations or cash flows.

13. OTHER INCOME (EXPENSE)

Other income consisted of the following for the three and six months ended January 31, 2008, respectively:

	Three Months Ended January 31, 2008	Six Months Ended January 31, 2008
Gain on settlements of derivative contract	$	$ 41
Change in fair value of derivative contract	44	(16)
Other		(7)
	$ 44	$ 18

Other income (expense) was $0 for both the three and six months ended January 31, 2007.

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations.

The discussion and analysis that follows should be read together with the accompanying unaudited consolidated financial statements and notes related thereto that are included under Item 1.

Overview and Outlook

We are an independent energy company incorporated under the laws of British Columbia, Canada and primarily engaged, through our wholly owned U.S. subsidiary, BPI Energy, Inc., in the exploration, production and commercial sale of coalbed methane (CBM). Our exploration and production efforts are concentrated in the Illinois Basin (the Basin), which encompasses a total area of approximately 60,000 square miles covering the southern two-thirds of Illinois, southwestern Indiana and northwestern Kentucky. Our Canadian activities are limited to administrative reporting obligations to the province of British Columbia and regulatory reporting to the British Columbia and Alberta Securities Commissions.

As of January 31, 2008, we owned or controlled CBM rights, through mineral leases, a farm-out agreement and ownership of a CBM estate, covering approximately 531,000 total acres in the Basin (approximately 98% of this acreage is undeveloped as of January 31, 2008). This total reflects an increase of approximately 2,000 acres in the second quarter of fiscal year 2008. Portions of our CBM rights are currently subject to litigation, as discussed in Item 1 of Part II below.

The State of Illinois (which includes most of the Basin) is estimated to be the number two state in the United States in terms of coal reserves; however, coal in the Basin is high in sulfur, discouraging coal mining operations. Recent advances in technology that can utilize higher sulfur coal and higher coal prices are combining to make coals in the Basin potentially attractive to mining operations. Although coal mining activities take priority over CBM operations in most of our acreage, we attempt to coordinate and plan our drilling and production activities in conjunction with the owners of the coal in order to minimize any potential disruptions. In addition, because of the long lead times involved in coal mining projects, our substantial acreage position, and our ability to be flexible with the timing and siting of our wells, we believe we can plan our work around coal mining operations in the vicinity of our projects.

We have been involved in the first two projects in the Basin that have commercially produced and sold CBM. We are the only company currently commercially producing and selling CBM in the State of Illinois. We believe our position as a first mover has enabled us to secure a substantial and favorable acreage position at costs that we believe compare very favorably to other CBM basins that are more mature in terms of production history.

We are an early stage CBM exploration and production company. We commenced CBM sales from our first producing wells during fiscal year 2005 (January 2005) and net gas sales volume for that fiscal year was 17.9 million cubic feet (MMcf). Since then, net sales volume has steadily grown to 135.1 MMcf in fiscal year 2006 and 185.3 MMcf in fiscal year 2007. During the current quarter, net gas sales volume was 64.5 MMcf, an increase of approximately 73% compared to 37.4 MMcf during the second quarter of fiscal year 2007 and an increase of approximately 13%

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compared to 56.8 MMcf during the previous quarter.

From early 2002 until 2005, our strategic focus was on building our acreage footprint in the Basin. We were built around the primary strategic objective of acquiring CBM rights in the Basin. As we began accumulating CBM rights, we began testing our acreage to determine its CBM potential. Having accumulated CBM rights to approximately 500,000 acres in the Basin and conducting extensive testing at our Southern Illinois Basin Project, we embarked (in late 2004) on a pilot production program at our Southern Illinois Basin Project. Encouraged by the results, we expanded our drilling and production activities and began installing the infrastructure necessary to enable us to begin sales of CBM at our Southern Illinois Basin Project.

As our drilling and production operations have grown, we have not abandoned our goal of adding additional acreage and mineral rights. Since the last quarter of fiscal year 2007, we have increased our acreage by approximately 19,000 acres, a 4% increase in total acreage. However, we have committed ourselves to transitioning from a company focused primarily on the acquisition of mineral rights to a company focused on expanding our drilling and production operations and growing our reserves.

In July 2007, we entered into a $75 million Credit Agreement with GasRock. The initial commitment under this agreement was $10.2 million, of which we drew $9.1 million at closing. In the first quarter of fiscal year 2008, GasRock increased the initial commitment to $10.7 million and extended the initial term of the Credit Agreement to January 30, 2009. GasRock will monitor operations, production and reserve growth for additional advances that we may request for additional development drilling. All future advances under the Credit Agreement beyond the initial commitment will be in the discretion of GasRock.

In April 2006, we initiated our second development front when we began drilling 10 pilot development wells in Shelby County at our Northern Illinois Basin Project. In May 2007, we announced our decision to continue production activities at our Shelby Pilot, while deferring additional development pending further production and pressure information. We use pilot projects to cost-effectively high-grade our extensive acreage position before committing development capital in a particular area. In the case of the Shelby Pilot, the pressure and production results to date do not provide a sufficient likelihood of commercial success to move into development at this early stage. Production history, as well as our ongoing work to reduce development costs and improve well performance, may make development at the Shelby Pilot area viable in the future. The Shelby Pilot represents only 400 acres of our 531,000-acre leasehold position.

In April 2007, we initiated our third pilot project in Macoupin County. This 12-well pilot program was completed at the end of the fourth quarter of fiscal year 2007 and consists of 10 pilot wells, one pressure observation well and one water disposal well. All 12 wells were drilled, completed and started pumping by July 2007. To date, we have not seen encouraging results from this pilot project.

In the second quarter of fiscal year 2008, we drilled four new wells at our Southern Illinois Basin Project, completed and tied in six new wells, including wells drilled in the previous quarter, and abandoned one older producing well during workover operations. The project currently has a total of 126 CBM wells producing approximately 900 thousand cubic feet (Mcf) per day. During this same quarter, we drilled two additional test wells. These test wells provide us with more data and further our understanding of the geology at their respective sites and deepen our knowledge of intra-basin variances.

We are not currently generating net income or positive cash flow from operations. Although we capitalize exploration and development costs, we have historically experienced significant losses. The primary costs that generated these losses were compensation-related expenses and general and administrative expenses. Even if we achieve increased revenues and positive cash flow from operations in the future, we anticipate increased exploration, development and other capital expenditures as we continue to explore and develop our mineral rights.

We have a cash balance of only $1.7 million as of March 10, 2008. We are not currently drilling new wells; however, based on the current trend in our cash used in operating activities and our current working capital situation, we need to raise cash during the third quarter of fiscal year 2008 in order to be able to settle our accounts payable and fund our net cash used in operating activities through the fiscal quarter ended April 30, 2008. Net cash used in operating activities was ($2,219,359) during the first quarter of fiscal year 2008 and ($1,389,219) during the second quarter of fiscal year 2008 for a total of ($3,608,578) during the first six months of fiscal year 2008. In addition, in order to continue as a going concern, we must be able to not only finance our current operations but also to pay amounts due under our Credit Agreement, when due on January 30, 2009, and finance any future exploration and development costs.

We have historically financed our activities primarily from the proceeds of private placements of our common shares and most recently from advances under the Credit Agreement. We are currently evaluating what options are available to finance current and future operations and are engaging in discussions with potential funding sources and transaction partners. We engaged Tristone Capital (U.S.A.), Inc. to assist in evaluating our potential options, which include additional advances under our Credit Agreement, which are at the discretion of GasRock, issuance of new debt and/or equity securities, joint ventures, mergers/combinations, asset sales or a combination of these alternatives. Although we are currently evaluating our options and are engaging in discussions with potential funding sources and transaction partners to raise the necessary funds, we can provide no assurance that we will be successful in completing a financing or transaction. Failure to raise adequate funds in the near term would have a material adverse effect on us.

Management s current focus is to raise the necessary capital to continue as a going concern so that we may continue focusing on our business strategy, which includes:

- continued development at our Southern Illinois Basin Project;
- continuing to obtain test data and initiate pilot projects to determine the commercial potential of CBM at our various acreage blocks and projects in the Basin;
- continuing to reduce well drilling and completion costs;
- continuing acreage acquisitions;
- increasing total company reserves; and
- growing total production.

In addition to our immediate need to raise cash, there are several factors over which we have little or no control that could impact our future economic success. These factors include natural gas prices, limitations imposed by the terms and conditions of our lease agreements, possible court rulings concerning our property interests in CBM, availability of drilling rigs, operating costs, and environmental and other regulatory matters. In our planning process, we have attempted to address these issues by:

- negotiating to obtain leases that grant us the broadest possible rights to CBM for any given tract of land;
- conducting ongoing title reviews of existing mineral interests;
- where possible, negotiating with and utilizing multiple service companies in order to increase competition and minimize the risk of disruptions caused by the loss of any one service provider; and
- attempting to create a low cost structure in order to reduce our vulnerability to many of these factors.

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Results of Operations

Three Months Ended January 31, 2008 Compared to Three Months Ended January 31, 2007

The following table presents our unaudited financial data for the second quarter of fiscal year 2008 compared to the second quarter of fiscal year 2007:

	Three Months Ended January 31,		Dollar	%
	2008	2007	Variance	Change
Revenue:				
Gas sales	$ 437,866	$ 246,906	$ 190,960	77%
Expenses:				
Lease operating expense	376,731	527,773	(151,042)	(29%)
General and administrative expense	1,519,457	1,469,516	49,941	3%
Lease rentals and other operating expense	78,540		78,540	100%
Depreciation, depletion and amortization	168,014	191,998	(23,984)	(12%)
Total operating expenses	2,142,742	2,189,287	(46,545)	(24%)
Operating loss	(1,704,876)	(1,942,381)	237,505	12%
Other income (expense):				
Interest income	33,995	166,416	(132,421)	(80%)
Interest expense	(30,268)	(3,026)	(27,242)	(900%)
Other income	44,000		44,000	100%
Total other income	47,727	163,390	(115,663)	(71%)
Net loss	$ (1,657,149)	$ (1,778,991)	$ 121,841	7%

Revenue During the second quarter of fiscal year 2008, net gas sales increased $190,960 compared to the second quarter of fiscal year 2007. Net sales of gas (net of royalties) were 64,481 Mcf for the second quarter of fiscal year 2008, or 73% higher compared to 37,352 Mcf for the second quarter of fiscal year 2007. Our average realized selling price per Mcf was $6.79 for the second quarter of fiscal year 2008, compared to $6.61 for the second quarter of fiscal year 2007.

Lease operating expense During the second quarter of fiscal year 2008, lease operating expense decreased $151,042 compared to the second quarter of fiscal year 2007. Lease operating expense represents production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental, workovers and labor and overhead expenses related to producing wells. The decrease is primarily due to non-recurring repairs and maintenance that occurred during the second quarter of fiscal year 2007. In addition, we are starting to realize benefits from our efforts to reduce ongoing lease operating expenses.

Lease rentals and other operating expense During the second quarter of fiscal year 2008, lease rentals and other operating expense increased $78,540 compared to the second quarter of fiscal year 2007. Lease rentals and other operating expense represents minimum lease rentals and shut-in royalties incurred on our leases that are not recoverable from future royalties of $32,525 and losses on settlement of asset retirement obligations (plugging wells) of $46,015.

General and administrative expense General and administrative expense consisted of the following for the second quarter of fiscal years 2008 and 2007, respectively:

	Three Months ended January 31, 2008	2007	Dollar Variance	% Change
Salaries and benefits	$ 359,388	$ 478,244	$ (118,856)	(25%)
Share-based payments	308,290	232,451	75,839	33%
Professional and regulatory	591,348	512,144	79,204	15%
Other	260,431	246,677	13,754	6%
Total general and administrative expense	$ 1,519,457	$ 1,469,516	$ 49,941	3%

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During the second quarter of fiscal year 2008, salaries and benefits decreased $118,856 compared to the second quarter of fiscal year 2007. The net decrease primarily relates to lower accrued bonuses during the current quarter.
During the second quarter of fiscal year 2008, non-cash expense associated with share-based payments increased $75,839 compared to the second quarter of fiscal year 2007. Share-based payments for the second quarter of fiscal year 2008 represent $212,290 of expense recognized on a pro rata basis for the anticipated vesting of restricted shares outstanding and $96,000 of expense recognized for directors fees. Share-based payments for the second quarter of fiscal year 2007 represent $232,451 of expense recognized on a pro rata basis for the anticipated vesting of restricted shares outstanding. We intend to continue to rely on the granting of equity-based awards, primarily restricted shares, in order to attract and retain qualified individuals and to conserve cash so that it may be utilized in executing our drilling program.
During the second quarter of fiscal year 2008, professional and regulatory expenses increased $79,204 compared to the second quarter of fiscal year 2007. The net increase is due to an increase in legal fees of approximately $220,000, primarily incurred in connection with litigation, offset by lower information technology consulting costs and other professional fees.
During the second quarter of fiscal year 2008, other general and administrative expenses increased $13,754 compared to the second quarter of fiscal year 2007. Other general and administrative expenses consist of rent, travel related expenses, telephone and utilities, other office expenses and non-cash amortization of costs capitalized in connection with the separation agreement entered into with our former Chief Financial Officer in October 2006. The net increase is due primarily to higher travel related expenses.
Depreciation, depletion and amortization expense During the second quarter of fiscal year 2008, depreciation, depletion and amortization (DD&A) decreased $23,984 compared to the second quarter of fiscal year 2007. We compute DD&A on capitalized acquisition and development costs using the units-of-production method based on estimates of proved reserves, and on other property and equipment using the straight-line method based on estimated useful lives ranging from three to five years. The decrease primarily resulted from the decrease in capitalized development costs due to a ceiling write-down of $11,722,153 at July 31, 2007, partially offset by an increase in amortization due to increased production over the second quarter of fiscal year 2008.
Interest income During the second quarter of fiscal year 2008, interest income decreased $132,421 compared to the second quarter of fiscal year 2007 due to significantly lower average cash balances during the second quarter of fiscal year 2008.
Interest expense During the second quarter of fiscal year 2008, interest expense increased $27,242 compared to the second quarter of fiscal year 2007. Interest incurred on debt during the current quarter, including amortization of deferred financing costs and debt discount, was $613,530 compared to $3,026 in the prior fiscal year quarter. This increase is due to the increase in debt outstanding under the GasRock Credit Agreement entered into on July 27, 2007. However, we capitalized $583,262 of the current quarter s interest expense to unproved gas properties in accordance with Statement of Financial Accounting Standards (SFAS) No. 34, Capitalization of Interest Costs.
Other income During the second quarter of fiscal year 2008, other income increased $44,000 compared to the second quarter of fiscal year 2007. We recognized a $44,000 gain on the change in fair value related to our derivative contract during the current quarter.
Six Months Ended January 31, 2008 Compared to Six Months Ended January 31, 2007
The following table presents our unaudited financial data for the first six months of fiscal year 2008 compared to the first six months of fiscal year 2007:

	Six Months Ended January 31,		Dollar	%
	2008	**2007**	**Variance**	**Change**
Revenue:				
Gas sales	$ 756,053	$ 540,909	$ 215,144	40%
Expenses:				

Lease operating expense	635,494	863,747	(228,253)	(26%)
General and administrative expense	3,403,462	4,204,227	(800,765)	(19%)
Lease rentals and other operating expense	78,840		78,840	100%
Depreciation, depletion and amortization	347,883	375,995	(28,112)	(7%)
Total operating expenses	4,465,679	5,443,969	(978,290)	(18%)
Operating loss	(3,709,626)	(4,903,060)	1,193,434	24%
Other income (expense):				
Interest income	130,531	385,322	(254,791)	(66%)
Interest expense	(32,194)	(6,179)	(26,015)	(421%)
Other income	18,177		18,177	100%
Total other income	116,514	379,143	(262,629)	(69%)
Net loss	$ (3,593,112)	$ (4,523,917)	$ 930,805	21%

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Revenue During the first six months of fiscal year 2008, revenue increased $215,144 compared to the first six months of fiscal year 2007. Net sales of gas (net of royalties) were 121,314 Mcf for the first six months of fiscal year 2008, or 37% higher compared to 88,842 Mcf for the first six months of 2007. Our average realized selling price per Mcf was $6.23 for the first six months of fiscal year 2008 compared to $6.09 for the first six months of fiscal year 2007. Net sales during the second quarter of fiscal year 2007 were negatively impacted by a nitrogen-related pipeline curtailment that began in October 2006 and necessitated six days of downtime followed by a period of constrained sales volume during the second quarter of fiscal year 2007.

Lease operating expense During the first six months of fiscal year 2008, lease operating expense decreased $228,254 compared to the first six months of fiscal year 2007. Lease operating expense represents production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental, workovers and labor and overhead expenses related to producing wells. The decrease is primarily due to non-recurring repairs and maintenance that occurred during the first six months of fiscal year 2007. In addition, we are starting to realize benefits from our efforts to reduce ongoing lease operating expenses.

Lease rentals and other operating expense During the first six months of fiscal year 2008, lease rentals and other operating expense increased $78,840 compared to the first six months of fiscal year 2007. Lease rentals and other operating expense represents minimum lease rentals and shut-in royalties incurred on our leases that are not recoverable from future royalties of $32,825 and losses on settlement of asset retirement obligations (plugging wells) of $46,015.

General and administrative expense General and administrative expense consisted of the following for the first six months of fiscal years 2008 and 2007, respectively:

	Six Months ended January 31,		**Dollar**	**%**
	2008	**2007**	**Variance**	**Change**
Salaries and benefits	$ 1,017,827	$ 1,570,391	$ (552,564)	(35%)
Share-based payments	671,480	877,302	(205,822)	(23%)
Professional and regulatory	1,228,946	1,318,536	(89,590)	(7%)
Other	485,209	437,998	47,211	11%
Total general and administrative expense	$ 3,403,462	$ 4,204,227	$ (800,765)	(19%)

During the first six months of fiscal year 2008, salaries and benefits decreased $552,564 compared to the first six months of fiscal year 2007. The net decrease primarily resulted from the inclusion of $350,000 of cash signing bonuses paid to newly hired members of our technical team and $250,000 of severance paid to our former Chief Financial Officer during the first six months of fiscal year 2007. This decrease is partially offset by the increase to current base salaries and accrued bonuses, reflecting full six-months salaries and benefits for the members of our technical team during the first six months of fiscal year 2008 as compared to partial salaries and benefits during the first six months of fiscal year 2007, as we did not employ our technical team for the entire six months of the prior fiscal year period.

During the first six months of fiscal year 2008, expense associated with share-based payments decreased $205,822 compared to the first six months of fiscal year 2007. Share-based payments for the first six months of fiscal year 2008 represent $477,980 of expense recognized on a pro rata basis for the anticipated vesting of restricted shares outstanding and $193,500 of expense recognized for directors fees. Share-based payments for the first six months of fiscal year 2007 represent $407,694 of expense recognized on a pro rata basis for the anticipated vesting of restricted shares outstanding and approximately $469,608 of expense related to the grant of 598,661 fully vested shares as inducement grants to newly hired members of our technical team, bonuses to officers and other employees, and fees to our directors. We intend to continue to rely on the granting of equity-based awards, primarily restricted shares, in order to attract and retain qualified individuals and to conserve cash so that it may be utilized in executing our drilling program.

During the first six months of fiscal year 2008, professional and regulatory expenses decreased $89,590 compared to the first six months of fiscal year 2007. The net decrease is primarily due to lower cash-based directors fees (incurred as share-based compensation expense during the first six months of fiscal year 2008), lower information technology consulting costs and other professional fees, offset by higher legal fees of approximately $240,000, primarily incurred in connection with litigation.

During the first six months of fiscal year 2008, other general and administrative expenses increased $47,211 over the first six months of fiscal year 2007. Other general and administrative expenses consist of rent, travel related expenses, telephone and utilities, other office expenses and non-cash amortization of costs capitalized in connection with the separation agreement entered into with our former Chief Financial Officer in October 2006. The net increase is due primarily to higher travel related expenses and higher non-cash amortization expense associated with the separation agreement.

Depreciation, depletion and amortization expense During the first six months of fiscal year 2008, DD&A decreased $28,112 compared to the first six months of fiscal year 2007. We compute DD&A on capitalized acquisition and development costs using the units-of-production method based on estimates of proved reserves, and on other property and equipment using the straight-line method based on estimated useful lives ranging from three to five years. The decrease primarily resulted from the decrease in capitalized development costs due to a ceiling write-down of $11,722,153 at July 31, 2007, partially offset by an increase in amortization due to increased production over the first six months of fiscal year 2008.

Interest income During the first six months of fiscal year 2008, interest income decreased $254,791 compared to the first six months of fiscal year 2007 due to significantly lower average cash balances during the first six months of fiscal year 2008.

Interest expense During the first six months of fiscal year 2008, interest expense increased $26,015 compared to the first six months of fiscal year 2007. Interest incurred on debt during the first six months of fiscal year 2008, including amortization of deferred financing costs and debt discount, was $1,115,456 compared to $6,179 in the comparable prior fiscal year period. This increase is due to the increase in debt outstanding under the GasRock Credit Agreement entered into on July 27, 2007. However, we capitalized $1,083,262 of interest expense incurred during the first six months of fiscal year 2008 to unproved gas properties in accordance with SFAS No. 34.

Other income During the first six months of fiscal year 2008, other income increased $18,177 compared to the second quarter of fiscal year 2007. We recognized a $40,940 gain on settlements and a $16,000 loss on the change in fair value related to our derivative contract during the first six months of fiscal year 2008. We also recognized other miscellaneous losses of $6,763 during the first six months of fiscal year 2008.

Critical Accounting Policies and Estimates

Our unaudited consolidated financial statements and accompanying notes have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires our management to make estimates, judgments and assumptions that affect reported amounts of assets, liabilities, revenues and expenses. On an ongoing basis, we evaluate the accounting policies and estimates that we use to prepare financial statements. We base our estimates on historical experience and assumptions believed to be reasonable under current facts and circumstances. Actual amounts and results could differ from these estimates used by management. Certain accounting policies that require significant management estimates and are deemed critical to our results of operations or financial position are discussed in Item 7 of our Annual Report on Form 10-K for the fiscal year ended July 31, 2007. There were no material changes in these policies during the current quarter other than the following:

Capitalized Interest

In accordance with SFAS No. 34, we capitalize interest costs to gas properties on expenditures made in connection with unproved properties that are not subject to current depletion. Interest is capitalized only for the period that activities are in progress to bring these properties to their intended use. Total interest expense incurred during the three and six months ended January 31, 2008, including the amortization of deferred financing costs and debt discount, was

$613,520 and $1,115,456, respectively. Of these

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amounts, interest costs capitalized to unproved gas properties during the three and six months ended January 31, 2008 were $583,262 and $1,083,262, respectively. No interest costs were capitalized in the comparable prior periods.

Financial Condition

Historically, our primary source of liquidity has come from the sale of our common shares in private placements and the proceeds from the exercise of warrants and options to acquire our common shares. On July 27, 2007, we closed the Advancing Term Credit Agreement with GasRock, as amended on November 29, 2007. The Credit Agreement provides for an initial commitment to us of $10.7 million and the possibility of future advances to us of up to an additional $64.3 million. All future advances under the Credit Agreement beyond the initial commitment will be made in GasRock s discretion. We may request advances under the Credit Agreement at any time before January 30, 2009, which GasRock may in its discretion extend until January 30, 2011. All amounts then outstanding under the Credit Agreement are due and payable on January 30, 2009, which GasRock may in its discretion extend until January 30, 2013. We have received advances totaling $10,780,719 under the Credit Agreement.

We did not begin to generate revenues from CBM sales until fiscal year 2005 (January 2005) and net gas sales volume for that fiscal year was only 17.9 MMcf. Since then, net sales volume has steadily grown to 135.1 MMcf in fiscal year 2006 and 185.3 MMcf in fiscal year 2007. During the current quarter, net gas sales volume was 64.5 MMcf, an increase of approximately 73% compared to 37.4 MMcf during the second quarter of fiscal year 2007 and an increase of approximately 13% compared to 56.8 MMcf during the previous quarter. Subject to the various risks described in this report, we expect revenue from the sale of our CBM to increase due to (i) increased production from existing wells as they continue to dewater and (ii) additional production generated as a result of drilling and production from additional wells. However, in view of our limited historical experience of dewatering and gas production in the Basin, we can provide no assurance that we will achieve a trend of increased production and revenue in the future.

In addition, CBM wells typically must go through a lengthy dewatering phase before making a meaningful contribution to gas production. We estimate that a typical vertical well will require about 24 months to reach peak production. The impact on our cash position is that there will be a delay of up to 24 months between the time we initially invest in drilling and completing a well and the time when a typical well will begin to make a meaningful contribution to our cash from operations. Additionally, net cash generated (used) by operating activities is dependent on a number of factors over which we have little or no control. These factors include, but are not limited to:

- the price of, and demand for, natural gas;
- availability of drilling equipment;
- lease terms;
- availability of sufficient capital resources; and
- the accuracy of production estimates for current and future wells.

We had a cash balance of $2,578,179 as of January 31, 2008, compared to $11,291,575 at July 31, 2007. The net decrease in our cash balance is the result of net cash used in operating activities of $3,606,578, consisting primarily of payments for salaries and benefits, professional fees and lease operating expenses, adjusted for changes in working capital, net cash used in investing activities of $6,659,280, consisting of capital expenditures related primarily to development costs, and net cash provided by financing activities of $1,552,462, consisting of $1,721,152 in additional borrowings from GasRock, less $127,070 of financing related costs associated with the GasRock Credit Agreement, $12,346 of payments on term notes and $29,274 of tax payments related to the vesting of employees common shares, which the employees surrendered to satisfy tax withholding obligations.

We have experienced significant losses in recent periods and have a cash balance of only $1.7 million as of March 10, 2008. We are not currently drilling new wells; however, based on the current trend in our cash used in operating activities and our current working capital situation, we need to raise cash during the third quarter of fiscal year 2008 in order to be able to settle our accounts payable and fund our net cash used in operating activities through the fiscal quarter ended April 30, 2008. Net cash used in operating activities was ($2,219,359) during the first six months of fiscal year 2008 and ($1,389,219) during the second quarter of fiscal 2008 for a total of ($3,608,578) during the first six months of fiscal year 2008. In order to continue as a going concern, we must be able to not only finance our current operations but also to pay amounts due under our Credit Agreement, when due on January 30, 2009, and finance any future exploration and development costs.

We have historically financed our activities primarily from the proceeds of private placements of our common shares and most recently from advances under the Credit Agreement. We are currently evaluating what options are available to finance current and future operations and are engaging in discussions with potential funding sources and transaction partners. We engaged Tristone Capital (U.S.A.), Inc. to assist in evaluating our potential options, which include additional advances under our Credit Agreement, which are at the discretion of GasRock, issuance of new debt and/or equity securities, joint ventures, mergers/combinations, asset sales or a combination of these alternatives. Although we are currently evaluating our options and are engaging in discussions with potential funding sources and transaction partners to raise the necessary funds, we can provide no assurance that we will be successful in completing a financing or transaction. Failure to raise adequate funds in the near term would have a material adverse effect on us.

We have no contractual commitments for capital expenditures. During the remaining six-month period ending July 31, 2008, our plans to drill new wells and acquire additional CBM rights depend on (i) our ability to secure additional financing; (ii) data obtained from test wells; (iii) data obtained from our pilot wells; and (iv) the risk factors described in this report.

Cautionary Statement Concerning Forward-Looking Statements

Some of the statements contained in this report that are not historical facts, including statements containing the words believes, anticipates, expects, intends, plans, should, may, might, continue and estimate and simil forward-looking statements under the federal securities laws. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements, or the conditions in our industry, on our properties or in the Basin, to be materially different from any future results, performance, achievements or conditions expressed or implied by such forward-looking statements. Some of the factors that could cause actual results or conditions to differ materially from our expectations, include, but are not limited to: (a) our inability to generate sufficient income, obtain sufficient financing, close an offering of debt or equity securities, or complete a merger/combination, joint venture, asset sale or other transaction that would enable us to fund our operations through the fiscal quarter ended April 30, 2008; (b) our inability to retain our acreage rights at our projects, at the expiration of our lease agreements, due to insufficient CBM production or for other reasons; (c) our failure to accurately forecast CBM production; (d) displacement of our CBM operations by coal mining operations, which have superior rights in most of our acreage; (e) our failure to accurately forecast the number of wells that we can drill; (f) a decline in the prices that we receive for our CBM production; (g) our failure to accurately forecast operating and capital expenditures and capital needs due to rising costs or different drilling or production conditions in the field; (h) our inability to attract or retain qualified personnel with the requisite CBM or other experience; (i) unexpected economic and market conditions, in the general economy or the market for natural gas; (j) limitations imposed on us by our Credit Agreement with GasRock; (k) our ability to repay or refinance the amounts advanced to us by Gas Rock when such amounts become due; and (l) potential exposure to losses caused by our derivative contract. We caution readers not to place undue reliance on these forward-looking statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Commodity Risk

Our major risk exposure is the commodity pricing applicable to our CBM production. Realized commodity prices received for our production are primarily driven by the spot prices attributable to natural gas. The effects of price volatility are expected to continue.

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Under the terms of our Credit Agreement with GasRock, we are required to enter into derivative contracts covering approximately 75% of our proved developed producing reserves scheduled to be produced during a two-year period at a guaranteed price of not less than $7.00 per one million of British thermal units (MMBtu). The objective is to reduce our exposure to commodity price risk associated with expected gas production. By achieving this objective, we may protect the outstanding debt amounts and maximize the funds available under our existing Credit Agreement, which helps us to support our annual capital budgeting and expenditure plans.

Our risk management strategy is to enter into commodity derivatives that set price floors and price ceilings for our natural gas production. On July 31, 2007, we entered into a costless collar contract with BP for the notional amount of 20,000 MMBtu per month beginning September 1, 2007 through July 31, 2009. Under the terms of the contract, BP is required to cover any shortfall below the floor of $7.00 per MMBtu and we must pay to BP any amounts above the ceiling of $11.00 per MMBtu as to the notional amount, with the price being based on the second to last close of the NYMEX forward price for each month. We expect that we will enter into additional derivative contracts during the next two years to cover the entire 75% of our proved developed producing reserves scheduled to be produced during that period.

We have elected not to designate the commodity derivative as a hedge, and accordingly, such contract is recorded at fair value on our consolidated balance sheets and changes in such fair value are recognized in current earnings as they occur. We do not hold or issue commodity derivatives for speculative or trading purposes. We are exposed to credit losses in the event of nonperformance by the counterparty to our commodity derivative. It is anticipated, however, that our counterparty, BP, will be able to fully satisfy its obligations under the commodity derivative contract. We do not obtain collateral or other security to support our commodity derivative contract subject to credit risk but we do monitor the credit standing of the counterparty.

Realized gains or losses from the settlement of gas derivative contracts are reported as other income or expense on the unaudited consolidated statements of operations. We entered into our first commodity derivative contract on July 31, 2007, with the first settlement month designated as September 2007. We recorded net realized gains on settlement of our derivative contract during the three and six months ended January 31, 2008 of $0 and $41,040, respectively, as other income in the unaudited consolidated statement of operations for the three and six months ended January 31, 2008.

Interest Rate Risk

Our exposure to changes in interest rates results from the Credit Agreement with GasRock. For the first year of the term of the Credit Agreement, all amounts outstanding under the Credit Agreement will bear interest at a rate equal to the greater of (i) 15% per annum and (ii) the LIBOR rate plus 9% per annum. If GasRock extends the Loan Termination Date, amounts outstanding under the Credit Agreement will thereafter bear interest at a rate equal to the greater of (i) 12% per annum and (ii) the LIBOR rate plus 6% per annum. The principal amount due under the credit facility at January 31, 2008 was $11,381,931. A 1% change in interest rates would affect pre-tax net loss by approximately $114,000 per year.

Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable and long-term notes payable. The carrying amount of cash equivalents, accounts receivable and accounts payable approximates fair market value due to the highly liquid nature of these short-term instruments.

Inflation and Changes in Prices

The general level of inflation affects our costs. Salaries and other general and administrative expenses are impacted by inflationary trends and the supply and demand of qualified professionals and professional services. Inflation and price fluctuations affect the costs associated with exploring for and producing CBM, which has a material impact on our financial performance.

Item 4. Controls and Procedures.

Our management is responsible for establishing and maintaining effective disclosure controls and procedures, as defined under Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (the Exchange Act). As of the end of the period covered by this report, we conducted an evaluation, under the supervision and with the participation of our Chief Executive Officer and Acting Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e)) as of January 31, 2008. Based on this evaluation, our Chief Executive Officer and Acting Chief Financial Officer concluded that our disclosure controls and procedures were effective as of January 31, 2008 in alerting them on a timely basis to material information relating to us (including our consolidated subsidiaries) required to be included in our periodic filings under the Exchange Act.

There were no significant changes in our internal control over financial reporting or in other factors that occurred during our last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Drummond Coal Co. Litigation

Approximately 115,000 acres of CBM rights of BPI Energy, Inc. (BPI) that are located at the Northern Illinois Basin Project are currently subject to litigation. To date, BPI has drilled one well on this acreage, a test well that was drilled in September 2006.

In 2004, BPI and affiliates of the Drummond Coal Co. (Drummond), including IEC (Montgomery), LLC (IEC), entered into a letter of intent to obtain coal and CBM gas rights for one another in the Illinois Basin and to work together in a relationship in which BPI would produce CBM from coal beds prior to the Drummond affiliates mining of coal from those beds. Pursuant to and in reliance upon this letter of intent and its relationship with Drummond, BPI arranged for the transfer of 163,109 acres of coal rights to the Drummond affiliates for a total purchase price of $5,845,500, which BPI believes reflects a significant discount to current market prices. In light of its obligations to Drummond, BPI charged no profit on its transfer of the coal rights to the Drummond affiliates.

Rather, in consideration for obtaining those coal rights, the Drummond affiliates were to lease approximately 115,000 acres of CBM rights to BPI for a primary lease term of 20 years and with favorable royalty rates. Although the Drummond affiliates entered into two CBM leases with BPI on April 26, 2006, they have since sought in various ways to void or terminate the leases.

Drummond affiliates IEC and Christian Coal Holdings, LLC (Christian) filed suit against BPI on February 9, 2007 in the United States District Court for the Northern District of Alabama, claiming that BPI has breached the CBM leases in various ways. On May 14, 2007, the Court granted BPI s motion to dismiss the case in its entirety on the ground of improper venue. IEC and Christian did not appeal that decision.

On March 13, 2007, BPI filed suit against IEC, Christian and additional Drummond affiliates Shelby Coal Holdings, LLC, Clinton Coal Holdings, LLC and Marion Coal Holdings, LLC in the United States District Court for the Southern District of Illinois. At the court s direction, BPI filed an amended complaint, and subsequently filed a second amended complaint that named BPI Energy Holdings, Inc. as an additional plaintiff, named Drummond Company Inc. and Drummond affiliate Vandalia Energy, LLC as additional defendants, and asserted additional claims. In its lawsuit, BPI seeks to rescind its transfers of coal rights to the Drummond affiliates for failure of consideration due to the Drummond affiliates efforts to avoid the CBM leases, has asserted claims for money damages for breach of the various agreements between the parties (including the CBM leases), breach of fiduciary duty, unjust enrichment, promissory estoppel, and tortious interference with contracts, and seeks to pierce the corporate veil to recover from Drummond and IEC for the actions of the other Drummond affiliates. The parties are currently engaged in written discovery. During the course of discovery, defendants produced an additional agreement between BPI and Christian that supported an additional claim for breach of contract, and as a result, BPI recently filed a Third Amended Complaint. Defendants have moved to stay the case on the basis that the agreement contains an arbitration provision. BPI is opposing defendants efforts to stay the case and arbitrate on the basis that defendants have waived the right to arbitrate. BPI also anticipates that defendants will file a motion to dismiss the Third Amended Complaint, because they filed motions to dismiss BPI s prior complaints. BPI anticipates that if the Court denies all or part of the motion to dismiss, Drummond and its affiliates will file counterclaims against BPI for breach of the CBM leases, citing the same bases set forth in the Alabama lawsuit.

BPI believes that Drummond and its affiliates, after having received favorable coal rights in exchange for favorable CBM rights, now wish to obtain a significant windfall by seeking to renege on the CBM rights that they were obligated to grant to BPI.

If the Drummond affiliates reinstitute their claims against BPI, we believe that we will be successful in defending against their claims of breach. However, there can be no assurance that we will be successful in maintaining these acreage rights. The loss of these acreage rights would not have a material impact on our financial position, results of operations or cash flows.

ICG Litigation

In November 2004, BPI entered into a farm-out agreement under which it acquired the right to develop certain CBM in Macoupin and Perry Counties in Illinois. The farm-out agreement covers 41,253 acres of CBM rights in Macoupin County and 22,997 acres of CBM rights in Perry County. The farmor was Addington Exploration, LLC, which leased the CBM rights from Meadowlark Farms, Inc. and Ayrshire Land Company. Meadowlark and Ayrshire went into bankruptcy, and ICG Natural Resources, LLC purchased their assets, including the CBM rights underlying the Addington leases. On April 9, 2007, ICG filed suit against BPI in Perry County, Illinois, in an effort to avoid the Addington leases, claiming that there was a lack of consideration at the time the leases were executed and that there is a lack of mutuality under the leases. BPI has denied ICG s claims, and is also defending on the grounds of estoppel by deed: that ICG acquired the CBM rights subject to those leases, as set forth in the deed from Ayrshire and Meadowlark to ICG, the purchase agreement between those parties, and numerous bankruptcy court filings and orders associated with the approval of the sale. BPI is also defending on the grounds that it is a bona fide purchaser of the farmout and assignment of the leases and that it expended substantial amounts to purchase and develop the leases prior to any notice or knowledge of the claims asserted by ICG. Addington was subsequently acquired by Nytis Exploration Company, LLC, which has intervened in the action. Both BPI and Addington have filed motions for summary judgment based upon estoppel by deed, and BPI has also moved for summary judgment as a bona fide purchaser. BPI recently learned that, subsequent to filing suit, ICG transferred its Perry County coal and possibly its Perry County CBM rights to Arch Minerals, which is not currently a party to the lawsuit. To date, Arch has not challenged the farm-out agreement. BPI has drilled 10 pilot wells, one water disposal well and three test wells on the acreage covered by the farm-out agreement. In February 2008, BPI shut down its Macoupin pilot and suspended development of the Perry County pilot in response to a demand by ICG that it do so until the litigation is resolved.

We believe that we will be successful in defending against ICG s claims; however, there can be no assurance that we will be successful in retaining the acreage under this farm-out agreement. The loss of these acreage rights would not have a material impact on our financial position, results of operations or cash flows.

Item 1A. Risk Factors.

The following risk factor is added to the risk factors that appear in our Annual Report on Form 10-K for the fiscal year ended July 31, 2007:

We may be unable to raise adequate capital in the near term, which would have a material adverse effect on our ability to continue as a going concern.

We have experienced significant losses in recent periods and have a cash balance of only $1.7 million as of March 10, 2008. We are not currently drilling new wells; however, based on the current trend in our cash used in operating activities and our current working capital situation, we need to raise cash during the third quarter of fiscal year 2008 in order to be able to settle our accounts payable and fund our net cash used in operating activities through the fiscal quarter ended April 30, 2008. Net cash used in operating activities was ($2,219,359) during the first quarter of fiscal year 2008 and ($1,389,219) during the second quarter of fiscal year 2008 for a total of ($3,608,578) during the first six months of fiscal year 2008. In order to continue as a going concern, we must be able to not only finance our current operations but also to pay amounts due under our Credit Agreement, when due on January 30, 2009, and finance any future exploration and development costs.

We have historically financed our activities primarily from the proceeds of private placements of our common shares and most recently from advances under the Credit Agreement. We are currently evaluating what options are available to finance current and future operations and are engaging in discussions with potential funding sources and transaction partners. We engaged Tristone Capital (U.S.A.), Inc. to assist in evaluating our potential options, which include additional advances under our Credit Agreement, which are at the discretion of GasRock, issuance of new debt and/or equity securities, joint ventures, mergers/combinations, asset sales or a combination of these alternatives. Although we are currently evaluating our options and are engaging in discussions with potential funding sources and transaction partners to raise the necessary funds, we can provide no assurance that we will be successful in completing a financing or transaction. Failure to raise adequate funds in the near term would have a material adverse effect on us.

There are no other material changes to the risk factors previously reported in our Annual Report on Form 10-K for the fiscal year ended July 31, 2007. For more information regarding such risk factors, please refer to Item 1A of our

Annual Report on Form 10-K for the fiscal year ended July 31, 2007.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None.

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Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

We held our Annual Meeting of Shareholders on December 17, 2007. As described in the Proxy Statement for the Annual Meeting, the following actions were taken:

(a) Election of Directors. The shareholders voted in favor of electing the following persons as Directors:

Name of Director	Number of Shares Voted For	Number of Shares Withheld
James G. Azlein	43,349,814	2,544,026
James E. Craddock	42,924,454	2,969,386
Dennis Carlton	44,494,713	1,399,127
Joseph P. McCoy	44,466,114	1,427,726
David E. Preng	42,911,435	2,982,405
Costa Vrisakis	42,875,878	3,017,962

(b) Appointment of Independent Registered Public Accounting Firm. The shareholders ratified the appointment of Meaden & Moore, Ltd. as our independent registered public accounting firm for 2008.

Votes For	45,736,280
Votes Against	30
Abstentions	0
Broker Non-Votes	157,530

Item 5. Other Information.

None.

Item 6. Exhibits.

31.1 Section 302 Certification of the Chief Executive Officer (Principal Executive Officer).

31.2 Section 302 Certification of the Acting Chief Financial Officer (Principal Financial Officer).

32.1 Section 906 Certification of the Principal Executive Officer and Principal Financial Officer.

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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.

BPI ENERGY HOLDINGS, INC.

Date: March 17, 2008

/s/ James G. Azlein
James G. Azlein,
President and Chief Executive Officer

/s/ Randall L. Elkins
Randall L. Elkins,
Controller and Acting Chief Financial Officer

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