BPI Energy Holdings, Inc.
Form 10-Q
March 19, 2007

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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, 2007
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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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 14, 2007: 72,524,493

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

BPI Energy Holdings, Inc.
Consolidated Balance Sheets

	January 31, 2007 (Unaudited)	July 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,255,781	$ 19,279,015
Accounts receivable	93,974	105,711
Other current assets	665,782	164,764
Total current assets	11,015,537	19,549,490
Property and equipment, at cost:		
Gas properties, full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $520,936 and $331,150	20,847,472	20,766,898
Unproved	6,096,085	3,368,231
Net gas properties	26,943,557	24,135,129
Other property and equipment, net of accumulated depreciation and amortization of $817,224 and $631,015	5,878,767	5,106,236
Net property and equipment	32,822,324	29,241,365
Restricted cash	100,000	100,000
Other non-current assets	367,168	161,125
Total assets	$ 44,305,029	$ 49,051,980
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 665,719	$ 1,492,239
Current maturity of long-term notes payable	33,397	140,866
Accrued liabilities and other	284,097	649,237
Total current liabilities	983,213	2,282,342
Long-term notes payable, less current portion	62,346	75,149
Asset retirement obligation	96,721	70,754
Total liabilities	1,142,280	2,428,245
Shareholders equity:		
	67,946,143	67,946,143

Common shares, no par value, authorized 200,000,000 shares, 72,524,493 and 70,812,540 outstanding		
Additional paid-in capital	6,934,050	5,871,120
Accumulated deficit	(31,717,444)	(27,193,528)
Total shareholders equity	43,162,749	46,623,735
Total liabilities and shareholders equity	$ 44,305,029	$ 49,051,980

See Notes to Unaudited Consolidated Financial Statements.

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BPI Energy Holdings, Inc.
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended January 31		Six Months Ended January 31	
	2007	2006	2007	2006
Revenues:				
Gas sales	$ 246,906	$ 327,811	$ 540,909	$ 537,505
Expenses:				
Lease operating expense	527,773	300,806	863,747	461,610
General and administrative expenses	1,469,516	1,165,483	4,204,226	2,437,239
Depreciation, depletion and amortization	191,998	117,890	375,995	212,692
	2,189,287	1,584,179	5,443,968	3,111,541
Operating loss	(1,942,381)	(1,256,368)	(4,903,059)	(2,574,036)
Other income (expenses):				
Interest income	166,416	270,186	385,322	402,804
Interest expense	(3,026)	(6,234)	(6,179)	(13,778)
Other income		138,191		137,523
	163,390	402,143	379,143	526,549
Net loss	$ (1,778,991)	$ (854,225)	$ (4,523,916)	$ (2,047,487)
Basic and diluted loss per share	($0.03)	($0.01)	($0.07)	($0.04)
Weighted average common shares outstanding	70,059,225	63,654,794	69,427,874	57,889,094

See Notes to Unaudited Consolidated Financial Statements.

BPI Energy Holdings, Inc.
Consolidated Statements of Shareholders Equity
(Unaudited)

	Common Shares		Additional Paid-in	Accumulated	Total Shareholders
	Shares	Amount	Capital	Deficit	Equity
Balance, July 31, 2006	70,812,540	$67,946,143	$5,871,120	$(27,193,528)	$46,623,735
Share-based payments common shares, including vesting of restricted shares	1,795,883		1,105,734		1,105,734
Surrender of shares	(83,930)		(42,804)		(42,804)
Net loss				(4,523,916)	(4,523,916)
Balance, January 31, 2007	72,524,493	$67,946,143	$6,934,050	$(31,717,444)	$43,162,749

See Notes to Unaudited Consolidated Financial Statements.

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BPI Energy Holdings, Inc.
Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended January 31	
	2007	2006
Operating activities:		
Net loss	$ (4,523,916)	$ (2,047,487)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation, depletion and amortization	375,995	212,692
Share-based payments	834,498	397,586
Gain on sale of investment		(127,416)
Accretion of asset retirement obligation	2,797	1,334
Changes in assets and liabilities:		
Accounts receivable	11,737	(124,963)
Other current assets	(278,629)	(246,911)
Accounts payable	(14,029)	203,778
Accrued liabilities and other	(565,140)	71,922
Other assets and liabilities		44,615
Net cash used in operating activities	(4,156,687)	(1,614,850)
Investing activities:		
Proceeds from sale of investment		551,000
Additions to gas properties	(3,719,803)	(6,819,644)
Additions to other property and equipment	(1,026,472)	(2,560,216)
Increase in restricted cash		(34,000)
Net cash used in investment activities	(4,746,275)	(8,862,860)
Financing activities:		
Payments on long-term notes payable	(120,272)	(57,458)
Net proceeds from issuance of common shares		29,907,372
Net cash (used in) provided by financing activities	(120,272)	29,849,914
Net (decrease) increase in cash and cash equivalents	(9,023,234)	19,372,204
Cash and cash equivalents at the beginning of the period	19,279,015	7,251,503
Cash and cash equivalents at the end of the period	$ 10,255,781	$ 26,623,707
Supplementary disclosure of cash flow information:		
Cash payments:		
Interest paid	$ 6,179	$ 9,856
Non-cash investing activities acquisition of equipment by issuance of notes payable		233,475

See Notes to Unaudited Consolidated Financial Statements.

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BPI Energy Holdings, Inc.
Notes to Consolidated Financial Statements
(Unaudited)

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., is involved in the exploration, production and commercial sale of coalbed methane 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. Amounts shown are in U.S. Dollars 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 quarter and six months ended January 31, 2007 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, 2006. Certain prior period amounts have been reclassified to conform to current period presentation.

The Company has financed its activities primarily from the proceeds of various share issuances. As a result of the Company being in the early stages of operations, the recoverability of assets on the balance sheet will be dependent on the Company s ability to obtain additional financing and to attain a level of profitable operations.

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 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 natural 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.

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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 not directly attributable to acquisition, exploration or development activities are expensed as incurred.

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 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.

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.

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 the end of each reporting period.

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.

No impairment existed as of January 31, 2007 or July 31, 2006.

Other Property and Equipment

Other property and equipment are stated at cost. Gas collection equipment is depreciated on the units-of-production method using estimates of proved reserves. Support equipment and other property and equipment are depreciated using the straight-line method over the estimated useful lives of the assets, ranging from three to 10 years. Major classes of other property and equipment consisted of the following at January 31, 2007 and July 31, 2006, respectively:

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	January 31, 2007	July 31, 2006
Other property and equipment:		
Gas collection equipment	$ 4,342,400	$ 4,342,400
Support equipment	1,832,444	1,046,989
Other	521,147	347,862
Less: Accumulated depreciation and amortization	(817,224)	(631,015)
	$ 5,878,767	$ 5,106,236

Loss Per Share

Basic loss per share is calculated using the weighted average number of common shares outstanding during the year. 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, 2007 and 2006, respectively, as the effect of their assumed exercises would be anti-dilutive:

	January 31, 2007	January 31, 2006
Outstanding warrants	5,311,600	10,763,603
Outstanding stock options	1,529,931	4,080,612
Nonvested portion of restricted shares issued	2,537,338	
	9,378,869	14,844,215

2. STOCK-BASED COMPENSATION

SFAS No. 123 (R)

In December 2004, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 123(R), Share-Based Payment. This Statement revises SFAS No. 123, Accounting for Stock-Based Compensation and supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees. 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 compensation expense at fair market value based on the grant-date fair value of those awards. Previously under SFAS 123, companies had the option of either recording expense based on the fair value of stock options granted or continuing to account for stock-based compensation using the intrinsic value method prescribed by APB No. 25.

The Company adopted SFAS No. 123(R), using the modified-prospective method, effective August 1, 2005. Since August 1, 2001, the Company followed the fair value provisions of SFAS 123 and recorded all share-based payment transactions as compensation expense at fair market value based on the grant-date fair value of those awards. In addition, all stock options previously granted by the Company vested immediately on the date of grant and, thus, there was no nonvested portion of previous stock option grants that vested during the fiscal year ended July 31, 2006 or thereafter. Therefore, the adoption of SFAS 123(R) had no impact on the Company s consolidated financial position or results of operations for the periods presented. The Company uses the Black-Scholes formula to estimate the fair value of stock options granted.

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Incentive Stock Option Plan

Prior to December 13, 2005 the Company administered a stock-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 shares 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. The following table summarizes information about options outstanding under the Incentive Stock Option Plan at January 31, 2007.

Exercise Price CAD$	Number Outstanding	Remaining Life (Years)	Expiry Date
$0.65	345,000	1.8	November 3, 2008
0.90	10,000	2.6	September 22, 2009
1.49	695,666	2.8	November 29, 2009
2.05	10,000	3.6	September 22, 2010
2.19	136,000	3.2	March 27, 2010
2.40	333,265	3.0	January 20, 2010
$1.56	1,529,931	2.7	

Omnibus Stock Plan

On December 13, 2005, the shareholders of the Company approved the Company s 2005 Omnibus Stock Plan (the Omnibus Stock Plan) and it became effective on that date. 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 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, 2007, the Company has issued 2,911,000 common shares (but no options) under the Omnibus Stock Plan and has 4,089,000 common shares available for future issuance under the Plan.

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Share-Based Transactions

The following table summarizes the Company s restricted share activity during the quarter and six months ended January 31, 2007:

	Shares	Weighted Avg. Grant Date Fair Value
Nonvested at July 31, 2006	2,325,000	$ 0.61
Granted	1,207,338	0.78
Vested	(475,000)	0.49
Nonvested at October 31, 2006	3,057,338	0.70
Vested	(520,000)	1.42
Nonvested at January 31, 2007	2,537,338	$ 0.74

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 lapse on the next lapse 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, 2007, there was $1,572,468 of unrecognized compensation cost related to restricted shares. The cost is expected to be amortized over a weighted average period of 1.3 years. The amount charged to expense related to restricted shares was $232,451 and $506,678 during the quarter and six months ended January 31, 2007, respectively, and $0 during both the quarter and six months ended January 31, 2006.

3. OTHER ASSETS

Other Current Assets

Other current assets consisted of the following at January 31, 2007 and July 31, 2006, respectively:

	January 31, 2007	July 31, 2006
Separation agreement	$ 352,353	$
Prepaid expenses	313,429	164,764
	$ 665,782	$ 164,764

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Other Non-current Assets

Other non-current assets consisted of the following at January 31, 2007 and July 31, 2006, respectively:

	January 31, 2007	July 31, 2006
Separation agreement	$ 206,043	$
Advance royalties	161,125	161,125
	$ 367,168	$ 161,125

Prepaid expenses primarily represent amounts paid one year in advance for commercial insurance premiums and monthly prepayments of rent, health benefits and other expenses. The separation agreement represents amounts capitalized related to non-compete/non-solicitation and continuing services clauses contained in a separation agreement entered into with a former officer of the Company on October 12, 2006. See note 10 for further explanation of this agreement.

4. ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other consisted of the following at January 31, 2007 and July 31, 2006, respectively:

	January 31, 2007	July 31, 2006
Employee compensation	$	$ 467,869
Separation agreement	200,000	
Professional and regulatory	52,952	111,805
Directors fees	27,000	31,000
Other	4,145	38,563
	$ 284,097	$ 649,237

The separation agreement represents amounts due related to a non-compete/non-solicitation clause contained in a separation agreement entered into with a former officer of the Company on October 12, 2006. See note 10 for further explanation of this agreement.

5. LONG-TERM NOTES PAYABLE

Long-term notes payable consisted of the following at January 31, 2007 and July 31, 2006, respectively:

	January 31, 2007	July 31, 2006
Case Credit term note due in fiscal year 2006, 6.50%	$ 7,236	$ 15,410
GMAC term note due in fiscal year 2009, 6.50%	17,446	20,608
GMAC term notes due in fiscal year 2010, 6.1% to 6.50%	71,061	80,849
Caterpillar Financial Services term note due in fiscal year 2007, 7.0%		99,148
	95,743	216,015
Less current maturities	(33,397)	(140,866)
Long-term notes payable	$ 62,346	$ 75,149

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The notes are collateralized by the related vehicles and equipment.

6. 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 obligation for the six months ended January 31, 2007 and 2006, respectively:

	Six Months Ended January 31, 2007	Six Months Ended January 31, 2006
Beginning asset retirement obligation	$ 70,754	$34,708
Additional liability incurred	6,994	9,907
Accretion expense	2,797	1,334
Change in estimate	35,377	
Asset retirement costs incurred	(36,239)	
Loss on settlement of liability	17,039	
Ending asset retirement obligation	$ 96,721	$45,949

During the six months ended January 31, 2007, the Company incurred $36,239 related to plugging wells in conjunction with the legal settlement reached with Colt LLC in fiscal year 2006. The actual cost of plugging the wells exceeded the Company s estimate resulting in a loss on settlement of the liability of $17,039. The Company changed its estimate of future costs associated with plugging wells, resulting in an increase to the asset retirement obligation of $35,377, which was recorded in the current quarter.

7. 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 that ensure 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

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equipment and crews could cause a delay in production and sales, which would affect operating results adversely.

8. INCOME TAXES

The Company operates in two tax jurisdictions, the United States and Canada. Primarily as a result of the net operating losses that the Company has generated (NOL Carryforwards) in both Canada and the United States, the Company has generated deferred tax benefits available for tax purposes to offset net income in future periods. SFAS No. 109, Accounting for Income Taxes requires that we 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, 2007.

9. SHAREHOLDERS EQUITY

Common shares The Company has authorized 200,000,000 shares without par value for which 72,524,493 and 70,812,540 were issued and outstanding as of January 31, 2007 and July 31, 2006, respectively. Shares issued and outstanding at January 31, 2007 include 2,537,338 of restricted shares expected to vest in future periods.

Additional paid-in capital Amounts recorded of $6,934,050 and $5,871,120 at January 31, 2007 and July 31, 2006, respectively, represent the cumulative value of share-based payments made as of each date.

Share purchase warrants outstanding at January 31, 2007 are as follows:

Number Outstanding	Exercise Price	Expiry Date
4,724,400	$1.50	December 13, 2007
643,200	1.25	December 31, 2009
394,000	1.25	January 12, 2010
5,311,600		

10. SEPARATION AGREEMENT

On October 12, 2006, the Company entered into a Separation Agreement and Waiver and Release (Separation Agreement) with a former officer and director of the Company. Under the terms of the Separation Agreement, the Company agreed to provide consideration to the former officer and director upon his resignation as follows:

Severance cash payment of $250,000 and medical and dental insurance coverage for two years from the date of the agreement. The cash payment of $250,000 was expensed during the first quarter of fiscal year 2007 and the cost of medical and dental coverage is being expensed as incurred.

Consulting issuance of 40,000 unrestricted common shares and cash payments totaling $50,000 in periodic installments from October 15, 2006 through December 31, 2006 in

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return for consulting services to be provided by the former officer and director as may be reasonably requested by the Company from time to time through January 2, 2008.

Non-Compete/Non-Solicitation cash payments of $100,000 on each of three dates from January 2, 2007 through January 2, 2008 and immediate vesting of 475,000 restricted shares held by the former officer and director in return for his agreeing not to compete with the Company or to solicit any of its employees for a period of two years.

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 unamortizing the related expense ratably over the future periods in which it expects to receive the related benefits. As of January 31, 2007, $558,397 of amortized value related to the consulting services and the non-compete/non-solicitation agreement are recorded as other assets on the balance sheet, including $206,043 shown as current and representing the amount to be amortized over the next year. The amount capitalized includes $228,432 of share-based payments representing the remaining unrecognized portion of expense related to the vesting of the 475,000 restricted shares. As of January 31, 2007, $200,000 is recorded as a current liability reflecting payments due under the non-compete/non-solicitation agreement within the next year. During the quarter and six months ended January 31, 2007, the Company expensed $90,061 and $108,660, respectively, in connection with the consulting services and the non-compete/non-solicitation agreement.

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 coalbed methane. 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 received $0 and $38,451 in expense reimbursement related to this arrangement during the six months ended January 31, 2007 and 2006, respectively. Mr. Oestreich s brother owns Dependable Service Company, a company that previously provided general labor services to the Company. The Company paid Dependable Services Company $0 and $160,679 during the six months ended January 31, 2007 and 2006, respectively.

David Preng, a director of the Company, owns Preng & Associates, an executive search firm specializing in the energy and natural resources industries. The Company paid Preng & Associates $9,621 and $20,000 for executive placement services during the six months ended January 31, 2007 and 2006, respectively.

12. SUBSEQUENT EVENT LEGAL PROCEEDINGS

BPI Energy, Inc. (BPI) is currently subject to litigation with respect to approximately 115,000 acres of its CBM rights that are located at the Northern Illinois Basin Project. To date, BPI has drilled one well on this acreage, a test well that was drilled in September 2006. This well is not currently at the production stage.

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 extract 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.

Ignoring mandatory arbitration provisions in the CBM 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. Specifically, although the CBM leases include no specific drilling commitments, IEC and Christian allege that BPI has breached the CBM leases by failing to use best efforts to commercially produce all economically recoverable gas. IEC and Christian also allege that BPI has breached the CBM leases by failing to provide maps of existing and proposed gas wells and facilities every six months and failing to maintain required insurance coverage. BPI refutes each of these allegations and intends to vigorously defend the Drummond affiliates claims of breach. In addition, BPI has moved to dismiss the lawsuit for lack of standing, lack of personal jurisdiction and improper venue, or in the alternative to transfer the case to either Ohio or Illinois.

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. 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, and has also asserted claims for money damages for breach of contract, breach of fiduciary duty, unjust enrichment and promissory estoppel.

We believe 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.

We believe that we will be successful in either having the lawsuit filed by the Drummond affiliates dismissed or 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.

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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 Securities Commission.

As of January 31, 2007, we owned or controlled CBM rights, through mineral leases, options to acquire mineral leases, a farm-out agreement and ownership of a CBM estate, covering approximately 500,000 total acres in the Basin (99% of this acreage is undeveloped as of January 31, 2007). Approximately 115,000 acres of our CBM rights are currently subject to litigation, as described in Item 1 of Part II below. We are focused on 12 Pennsylvanian coal seams that we regard as having commercial CBM potential. The seams in the acreage covered by our CBM rights have an aggregate thickness of 11-27 feet with a 19-foot median. We plan to complete several individual seams per well that range from two to nine feet thick each. Gas desorption tests of these coals have yielded 13-113 scf/ton with a 63 scf/ton median. Extensive permeability testing of individual seams (before stimulation) indicates a range of 0.2-75 millidarcies and median of 4 millidarcies.

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 and one of only two companies currently commercially producing and selling CBM in the Basin. 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 in January 2005. Net gas sales during the fiscal year ended July 31, 2005 were $117,835 on sales volume of 17,885 Mcf. Net gas sales were $1,126,477 on sales volume of 135,118 Mcf for the fiscal year ended July 31, 2006, an increase of 856% in net gas sales and 655% in sales volume over the prior year. Net gas sales for the current quarter were $246,906 on sales volume of 37,352 Mcf compared to net gas sales of $327,811 on sales volume of 27,395 Mcf in the same prior year quarter, representing a decrease of 25% in net gas sales and an increase of 36% in sales volume over the same quarter from the previous year. Net gas sales and sales volume for the quarter ended January 31, 2007 were lower by 16% and 27%, respectively, compared to the previous quarter due primarily to a nitrogen-related pipeline curtailment that began in October and necessitated six days of downtime followed by a period of constrained sales volume. The curtailment was caused by an increase in the nitrogen content of the sales stream to approximately 5.5% versus a pipeline quality specification of 4.0% total inert components. This is possibly due to adding new wells and new coal seams in the field, since coals preferentially desorb nitrogen, causing the highest nitrogen content to be early in the life of a new well or seam. A nitrogen-rejection unit is currently being installed, with start-up anticipated during March 2007. In the meantime, the field remains online, the coals are continuing to de-water, and we are selling gas at a constrained rate.

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. However, we have committed ourselves to transitioning BPI 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. To accomplish this transition, we recognized that we needed to obtain additional capital, resources and technical expertise. We believe that we have made substantial progress in achieving these goals. In September 2005, we sold 18,000,000 common shares and raised approximately $28,000,000. In April 2006, we hired Jim Craddock as our Senior Vice President of Operations (recently promoted to Chief Operating Officer). Prior to joining us, Mr. Craddock was with Burlington Resources for over 20 years, last serving as Chief Engineer. In his first few months at BPI, Mr. Craddock built a strong in-house technical team by adding a geologist and three engineers to our team, all with extensive experience in successful CBM projects in basins located in the United States and Canada. Our new technical team has over 130 years of experience in CBM exploration and development that they bring to us.

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. Pilot production is being monitored and results to date continue to be encouraging. We have completed drilling two additional pilot wells and a pressure observation well at Shelby, which will be put into operation by the end of March as our technical team continues its evaluation of the Shelby pilot production. We plan to make a decision regarding development at Shelby by the end of April 2007.

The first of five test wells planned to be drilled during the balance of fiscal 2007 is currently being drilled in Clinton County.

An additional water disposal well has been drilled at the Southern Illinois Basin Project and a second rig has just started drilling additional production wells at the Southern Illinois Basin Project.

We previously announced plans to drill a total of 29 new production wells during the balance of fiscal 2007. This drilling plan will also include a new 10-well pilot program and a disposal well.

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.

Our current plan anticipates that for the remaining six months of fiscal year 2007, we will spend approximately $10.5 million to drill 50 new wells, which includes 29 development wells, 12 pilot wells, three pressure observation wells, one water disposal well and five test wells. In addition to our drilling program, we expect to continue to pursue the acquisition of additional CBM rights during the fiscal year. Our cash balance at January 31, 2007 of $10,255,781 is insufficient to fully fund our forecasted capital expenditures and net cash used by operating activities during our 2007 fiscal year or our operations beyond that date. We expect that the capital expenditure requirements related to our drilling program and our other cash requirements will be funded by our cash balance and cash raised through the issuance of debt securities, equity securities, borrowings and/or joint ventures, all of which we are actively pursuing. Although we are currently evaluating the best methods of raising those funds, we can provide no assurance that we will be able to raise the necessary funds.

Management s focus for the remainder of fiscal year 2007 will be to:

obtain test data and initiate pilot projects that demonstrate the commercial potential of CBM at our various acreage blocks and projects in the Basin;

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- continue to reduce well drilling and completion costs;
- increase total company reserves; and
- grow total production.

Gathering test data and siting pilot projects based on this data should lead to proving project viability in multiple areas in the Basin. These pilot projects may have the potential to grow into development projects that will increase our total reserves and production. As we drill new wells, our production should continue to increase, as the new wells come online and our existing wells continue to dewater. As our production increases in the future, we should be positioned to generate positive cash flow from our operations.

A thorough technical evaluation of the assets that we control should lead to more cost effective drilling and completion techniques that can be implemented to improve capital efficiency, increase resource recovery and total reserves and improve internal rates of return from development projects.

We currently control approximately 500,000 acres of CBM rights and, assuming 80-acre vertical well spacing and the development of all of our acreage, have the possibility for up to 6,000 drilling locations. With our potential for drilling locations, we expect that our drilling activities will be taking place over many years. The type of test data we are interested in developing across all of our projects includes measurements of permeability, gas content and net pay (i.e., thickness of coal seams from which we believe CBM can be commercially produced). Our focus is to increase our technical and operational knowledge of the Basin and our acreage rights to assist us in (i) establishing the value of our CBM assets and (ii) optimizing the production we can obtain from our wells after we bring them online. The technical team we have assembled has extensive experience and expertise in all of these areas as well as implementation of large scale development of CBM projects.

Several factors, over which we have little or no control, 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, 2007 Compared to Three Months Ended January 31, 2006

The following table presents our unaudited financial data for the second quarter of fiscal year 2007 compared to the second quarter of fiscal year 2006:

	Three Months Ended January 31,			
	2007	2006	Dollar Variance	% Change
Revenues:				
Gas sales	$ 246,906	$ 327,811	$ (80,905)	(25%)
Expenses:				
Lease operating expense	527,773	300,806	226,967	75%
General and administrative expense	1,496,516	1,165,483	304,033	26%
Depreciation, depletion and amortization	191,998	117,890	74,108	63%
	2,189,287	1,584,179	605,108	38%
Operating loss	(1,942,381)	(1,256,368)	(686,013)	(55%)
Other income (expense):				
Interest income	166,416	270,186	(103,770)	(38%)
Interest expense	(3,026)	(6,234)	3,208	51%
Other income		138,191	(138,191)	(100%)
	163,390	402,143	(238,753)	(59%)
Net loss	$(1,778,991)	$ (854,225)	$(924,766)	(108%)

Revenue During the second quarter of fiscal year 2007, revenue decreased $80,905 over the second quarter of fiscal year 2006. Net sales of gas (net of royalties) were 37,352 Mcf for the second quarter of fiscal year 2007 or 36% higher compared to 27,395 Mcf for the second quarter of 2006. Our average realized selling price per Mcf was $6.61 for the second quarter of fiscal year 2007 compared to $11.97 for the second quarter of fiscal year 2006. Net sales were also negatively impacted during the second quarter of fiscal year 2007 due to a nitrogen-related pipeline curtailment. A nitrogen-rejection unit is currently being constructed, with start-up anticipated during March 2007.

Lease operating expense During the second quarter of fiscal year 2007, lease operating expense increased $226,967 over the second quarter of fiscal year 2006. Lease operating expenses represent production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental, workovers and labor and overhead expenses directly related to producing wells. The increase is primarily due to expenses associated with non-recurring workover projects in process at the Southern Illinois Basin Project designed to increase production of existing wells, as well as an increase in the number of producing wells and the related costs incurred due to the increase in gas production at the Southern Illinois Basin Project, new lease operating expenses at our pilot project in the Northern Illinois Basin, and the hiring of additional personnel.

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General and administrative expense General and administrative expense consisted of the following for the second quarter of fiscal years 2007 and 2006, respectively:

	Three Months ended January 31,			
	2007	2006	Dollar Variance	% Change
Salaries and benefits	$ 568,305	$ 503,368	$ 64,937	13%
Share-based payments	232,451		232,451	100%
Professional and regulatory	497,730	511,904	(14,174)	(3%)
Other	171,030	150,211	20,819	14%
Total general and administrative expense	$1,469,516	$1,165,483	$304,033	26%

During the second quarter of fiscal year 2007, salaries and benefits increased $64,937 over the second quarter of fiscal year 2006. Salaries and benefits associated with base salaries increased approximately $260,000 primarily as a result of hiring additional personnel to support our growth, including our Chief Operating Officer, three engineers and a geologist. This increase was partially offset by approximately $200,000 of expense associated with executive bonuses recognized during the second quarter of fiscal year 2006.

During the second quarter of fiscal year 2007, expense associated with share-based payments increased $232,451 over the second quarter of fiscal year 2006. Share-based payments for the second quarter of fiscal year 2007 represent non-cash expense recognized 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.

Depreciation, depletion and amortization expense During the second quarter of fiscal year 2007, depreciation, depletion and amortization expense (DD&A) increased $74,108 over the second quarter of fiscal year 2006. We compute DD&A on capitalized acquisition and development costs (including gas collection equipment) using the units-of-production method based on estimates of proved reserves, and on all other property and equipment using the straight-line method based on estimated useful lives ranging from three to 10 years. The increase is primarily due to the increase in capitalized development costs and an increase in production over the second quarter of fiscal year 2006. Additionally, depreciation expense increased due to additions to other support equipment utilized in our development of gas reserves.

Interest income During the second quarter of fiscal year 2007, interest income decreased $103,770 over the second quarter of fiscal year 2006 due to lower average cash balances during the second quarter of fiscal year 2007.

Other income During the second quarter of fiscal year 2007, other income decreased $138,191 from the second quarter of fiscal year 2006 primarily due to the gain of $127,416 that we recognized on the sale of our investment in Hite Coalbed Methane L.L.C. in January 2006.

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Six Months Ended January 31, 2007 Compared to Six Months Ended January 31, 2006

The following table presents our unaudited financial data for the first six months of fiscal year 2007 compared to the first six months of fiscal year 2006:

	Six Months Ended January 31,		Dollar	%
	2007	2006	Variance	Change
Revenues:				
Gas sales	$ 540,909	$ 537,505	$ 3,404	1%
Expenses:				
Lease operating expense	863,747	461,610	402,137	87%
General and administrative expense	4,204,226	2,437,239	1,766,987	72%
Depreciation, depletion and amortization	375,995	212,692	163,303	77%
	5,443,968	3,111,541	2,332,427	75%
Operating loss	(4,903,059)	(2,574,036)	(2,329,023)	(90%)
Other income (expense):				
Interest income	385,322	402,804	(17,482)	(4%)
Interest expense	(6,179)	(13,778)	7,599	55%
Other income		137,523	(137,523)	(100%)
	379,143	526,549	(147,406)	(28%)
Net loss	$ (4,523,916)	$ (2,047,487)	$ (2,476,429)	(121%)

Revenue During the first six months of fiscal year 2007, revenue increased $3,404 over the first six months of fiscal year 2006. Net sales of gas (net of royalties) were 88,842 Mcf for the first six months of fiscal year 2007 or 88% higher compared to 47,183 Mcf for the first six months of 2006. Our average realized selling price per Mcf was $6.09 for the first six months of fiscal year 2007 compared to $11.39 for the first six months of fiscal year 2006. Net sales were also negatively impacted by a nitrogen-related pipeline curtailment that began in October and necessitated six days of downtime followed by a period of constrained sales volume during the second quarter of fiscal year 2007. A nitrogen-rejection unit is currently being constructed, with start-up anticipated during March 2007.

Lease operating expense During the first six months of fiscal year 2007, lease operating expense increased $402,137 over the first six months of fiscal year 2006. Lease operating expense represents production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental, workovers and labor and overhead expenses directly related to producing wells. The increase is primarily due to expenses associated with non-recurring workover projects in process at the Southern Illinois Basin Project designed to increase production of existing wells, as well as an increase in the number of producing wells and the related costs incurred due to the increase in gas production at the Southern Illinois Basin Project, new lease operating expenses at our pilot project in the Northern Illinois Basin and the hiring of additional personnel.

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General and administrative expense General and administrative expense consisted of the following for the first six months of fiscal years 2007 and 2006, respectively:

	Six Months ended January 31,			
	2007	2006	Dollar Variance	% Change
Salaries and benefits	$ 1,779,051	$ 727,240	$ 1,051,811	145%
Share-based payments	877,302	397,586	479,716	121%
Professional and regulatory	1,204,122	1,072,142	131,980	12%
Other	343,751	240,271	103,480	43%
Total general and administrative expense	$ 4,204,226	$ 2,437,239	$ 1,766,987	72%

During the first six months of fiscal year 2007, salaries and benefits increased $1,051,811 over the first six months of fiscal year 2006. The net increase was primarily the result of annual bonuses incurred during the first quarter of fiscal year 2007 and increased compensation associated with hiring additional personnel to support our growth, including our Chief Operating Officer, three engineers and a geologist, including cash signing bonuses totaling $350,000 paid to such personnel during the quarter. In addition, expense for the first six months of fiscal year 2007 includes $250,000 severance paid to our former Chief Financial Officer and General Counsel who resigned in October 2006.

During the first six months of fiscal year 2007, expense associated with share-based payments increased $479,716 over the first six months of fiscal year 2006. Share-based payments for the first six months of fiscal year 2007 represent non-cash expense recognized for the anticipated vesting of restricted shares outstanding, the grant of 350,000 unrestricted common shares to newly hired members of our technical team and the grant of 248,661 unrestricted common shares to certain executive officers, employees and non-employee directors related to bonuses and directors fees. During the first six months of fiscal year 2006, we granted options to purchase 495,000 common shares that were valued at $.80 per option using the Black-Scholes valuation method. 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 2007, professional and regulatory expenses increased $131,980 over the first six months of fiscal year 2006. The net increase is due to higher professional advisory fees of approximately $160,000, higher I.T. consulting fees of approximately $65,000 related to implementation of our new management reporting and ERP system, and employee relocation fees of approximately $155,000 incurred related to the hiring of our new technical team. These increases were partially offset by lower professional and regulatory fees associated with filing initial SEC registration statements and listing on the American Stock Exchange, including legal, accounting, financial printing and initial listing fees, which decreased in the aggregate by approximately $250,000 from the first six months of fiscal year 2006.

During the first six months of fiscal year 2007, other general and administrative expenses increased $103,480 over the first six months of fiscal year 2006, primarily due to additional rent and office expenses related to the Edwardsville, Illinois office, which opened in May 2006, and higher travel-related expenses associated with increased investor relations activities.

Depreciation, depletion and amortization expense During the first six months of fiscal year 2007, DD&A increased $163,303 over the first six months of fiscal year 2006. We compute DD&A on capitalized acquisition and development costs (including gas collection equipment) using the units-of-production method based on estimates of proved reserves, and on all other property and equipment using the straight-line method based on estimated useful lives ranging from three to 10 years. The increase is primarily due to the increase in capitalized development costs and an increase in production over the first six months of fiscal year 2006. Additionally, depreciation expense increased due to additions to other support equipment.

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Other income During the first six months of fiscal year 2007, other income decreased $137,523 from the first six months of fiscal year 2006, primarily due to the gain of $127,416 that we recognized on the sale of our investment in Hite Coalbed Methane L.L.C. in January 2006.

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, 2006. There were no material changes in these policies during the current quarter.

Financial Condition

Our primary source of liquidity historically 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. To date, we have not relied significantly on borrowing to finance our operations or provide cash. As of January 31, 2007, we had only $95,743 in long-term notes payable. From July 31, 2003 until January 31, 2007, we raised $43,198,616 from the sale of our common shares. Additionally, during that same period, we collected $6,728,810 and $2,042,280 as a result of the exercise of warrants and stock options, respectively. Our primary use of these funds has been the acquisition, exploration, testing and development of our CBM properties and rights and payment of general and administrative expenses required to support our operations.

We did not begin to generate revenues from CBM sales until January 2005. Revenues from CBM sales were $540,909 and $537,505 for the first six months of fiscal years 2007 and 2006, respectively, and $246,906 and $327,811 for the quarters ended January 31, 2007 and 2006, respectively. 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 the fact that we have very little 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 significant 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 significant 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.

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We had a cash balance of $10,255,781 as of January 31, 2007, compared to $19,279,015 at July 31, 2006. The net decrease in our cash balance is primarily due to the net cash used in operating activities of $4,156,687, consisting primarily of payments for salaries and benefits, professional fees and lease operating expenses adjusted for changes in working capital, and net cash used in investing activities of $4,746,275, consisting of $3,719,803 of development costs, primarily at our Northern Illinois Basin Project, and $1,026,472 of other property and equipment, which includes a nitrogen rejection unit being installed at our Southern Illinois Basin Project, vehicles and equipment to support development and other support equipment. We also made repayments of long-term notes in the amount of $120,272 during the current fiscal year.

We have no significant contractual commitments for capital expenditures. However, our plan anticipates that for the remaining six months of fiscal year 2007, we will spend approximately $10.5 million to drill 50 new wells, which includes 29 development wells, 12 pilot wells, three pressure observation wells, one water disposal well and five test wells. In addition to our drilling program, we expect to continue to pursue the acquisition of additional CBM rights during the fiscal year. We expect that the capital expenditure requirements related to our drilling program and our other cash requirements will be funded by our cash balance and cash raised through the sale of debt securities, equity securities, borrowings and/or joint ventures, all of which we are actively pursuing. Although we are currently evaluating the best methods of raising these funds, we can provide no assurance that we will be able to raise the necessary funds.

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 or obtain sufficient financing to fund our operations or drilling plan through July 31, 2007 or thereafter; (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; and (i) unexpected economic and market conditions, in the general economy or the market for natural gas. 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.

Interest Rate Risk

All of our debt has fixed interest rates, so consequently we are not exposed to cash flow or fair value risk from market interest rate changes on this debt.

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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 approximate 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
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 Controller (who is currently responsible for performing certain functions of our principal financial officer), of the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)). Based on this evaluation, our Chief Executive Officer and Controller have concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.
There have been no changes in our internal control over financial reporting identified in connection with the evaluation required by Rule 13a-15(d) of the Exchange Act that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.
PART II. OTHER INFORMATION
Item 1. Legal Proceedings
BPI Energy, Inc. (BPI) is currently subject to litigation with respect to approximately 115,000 acres of its CBM rights that are located at the Northern Illinois Basin Project. To date, BPI has drilled one well on this acreage, a test well that was drilled in September 2006. This well is not currently at the production stage.
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 extract 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.
Ignoring mandatory arbitration provisions in the CBM 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. Specifically, although the CBM leases include no specific drilling commitments, IEC and Christian allege that BPI has breached the CBM leases by failing to use best efforts to commercially produce all economically recoverable gas. IEC and Christian also allege that BPI has breached the CBM leases by failing to provide maps of existing and proposed gas wells and facilities every six months and failing to maintain required insurance coverage. BPI refutes each of these allegations and intends to vigorously defend the Drummond affiliates claims of breach. In addition, BPI has moved to dismiss the lawsuit for lack of standing, lack of personal jurisdiction and improper venue, or in the alternative to transfer the case to either Ohio or Illinois.
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. 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, and has also asserted claims for money damages for breach of contract, breach of fiduciary duty, unjust enrichment and promissory estoppel.

We believe 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.

We believe that we will be successful in either having the lawsuit filed by the Drummond affiliates dismissed or 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.

Item 1A. Risk Factors

There are no material changes to the risk factors previously reported in our Annual Report on Form 10-K for the fiscal year ended July 31, 2006. 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, 2006.

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

None.

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 18, 2006. 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	37,043,661	1,697,688
Dennis Carlton	36,303,414	2,437,935
William J. Centa	36,285,691	2,455,658
David E. Preng	37,112,913	1,628,436
Costa Vrisakis	37,087,140	1,654,209

(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 2007.

Votes For	38,020,559
Votes Against	0
Abstentions	720,789
Broker Non-Votes	1

(c) Approval of Amendment to the Omnibus Stock Plan. The shareholders approved an amendment to the Omnibus Stock Plan to increase the cap on the aggregate number of common shares that we can issue under the Plan from 5,000,000 to 7,000,000:

Votes For	10,099,906
Votes Against	6,234,600
Abstentions	0
Broker Non-Votes	22,406,843

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 19, 2007

/s/ James G. Azlein

James G. Azlein,
President and Chief Executive Officer

/s/ Randy L. Elkins

Randy L. Elkins,
Controller and Acting Chief Financial Officer