BPI Energy Holdings, Inc.
Form 10-K
October 29, 2007

Table of Contents

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

Form 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended July 31, 2007

Commission File Number: 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
(440) 248-4200
(Address and telephone number of principal executive offices)

Securities registered under Section 12(b) of the Exchange Act:

Title of Each Class	**Name of Exchange on Which Registered**
Common Shares, without par value	American Stock Exchange

Securities registered under Section 12(g) of the Exchange Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

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, and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers in response to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter: $26,149,553.

As of October 22, 2007, there were 73,792,493 shares of the Registrant s Common Shares (without par value) outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Certain portions of Part III are incorporated by reference to the Registrant s definitive proxy statement.

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Some of the statements contained in this report and other materials we file with the Securities and Exchange Commission (SEC), or in other written or oral statements made or to be made by us, other than statements of historical fact are forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements give our current expectations or forecasts of future events. Statements containing the words believes, anticipates, expects, intends, plans, predict, strategy, budget, project, potential, continue and estimate and similar words are used to identify forward-looking statements. 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 Illinois 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 the factors discussed in this report under the heading Risk Factors and elsewhere.

Given these uncertainties, you should not place undue reliance on such forward-looking statements. Except as otherwise required by applicable law, we undertake no obligation to publicly update or revise any forward-looking statements, the risk factors or other information described in this report, whether as a result of new information, future events, changed circumstances or any other reason after the date of this report.

Table of Contents

PART I

ITEM 1. *Business.*

Coalbed Methane

We are engaged in the exploration, production and commercial sale of coalbed methane (CBM). CBM is a form of natural gas that is generated during coal formation and is contained in underground coal seams and abandoned mines.

Methane is the primary commercial component of natural gas produced from conventional gas wells. Natural gas produced from conventional wells generally contains other hydrocarbons in varying amounts that require the natural gas to be processed. CBM is generally pipeline-quality gas after simple water dehydration and removal of traces of nitrogen and other impurities.

CBM production is similar to conventional natural gas production in terms of the physical producing facilities. However, the subsurface mechanisms that allow gas movement to the wellbore are very different. Conventional natural gas wells require a subsurface that is porous, allows the gas to migrate easily, and contains a natural trap to capture and hold the gas reservoir. In contrast, CBM is held in place within coal seams in four ways:

- as free gas within the micropores (pores with a diameter of less than .0025 inch) and cleats (set of natural fractures) of coal;
- as dissolved gas in water within the coal;
- as adsorbed gas held by molecular attraction on the surface of macerals (organic constituents that comprise the coal mass), micropores and cleats in the coal; and
- as adsorbed gas within the molecular structure of the coal.

Coal at shallower depths with good cleat development contains high concentrations of free and dissolved methane gas. Adsorption is generally higher in coal that contains a higher percentage of fixed carbon and generally increases with higher pressure, which occurs at deeper depths. Our current wells range in depths from 450 to 1,300 feet beneath the surface.

CBM gas is released from the coal by pressure changes when water is removed from coal. In contrast to conventional gas wells, new CBM wells initially produce mostly water for several months. As pressure decreases in the coal formation, methane gas is released from the coal.

To assist you in reading this report and understanding our business, we have included a glossary of selected natural gas terms that are used in this report. The glossary is set forth as Appendix A beginning on Page A-1.

Our Business

We focus on the acquisition, exploration, development and production of CBM reserves located in the Illinois Basin, which covers approximately 60,000 square miles in the mid to southern part of Illinois, southwest Indiana and northwest Kentucky. Through lease and farm-out agreements and ownership of a CBM estate, we have assembled CBM rights covering approximately 512,000 acres in the Illinois Basin.

A Gas Technology Institute report from 2001 estimates that 21 trillion cubic feet of CBM gas is in place in the Illinois Basin. Although the Illinois Basin is believed to have significant CBM potential, it is largely untested for commercial CBM production. In addition, we have evaluated the CBM potential in only a relatively small part of our acreage rights.

Our acreage rights in the Illinois Basin are currently divided into three projects. Our Southern Illinois Basin Project consists of approximately 10,000 acres in the southern part of the Illinois Basin. Our other acreage holdings include our Northern Illinois Basin Project, located in the north central part of the Illinois Basin, where we control through lease and farm-out agreements an aggregate of 366,364 acres of CBM rights. Our other project is our Western Illinois Basin Project, located in the northwestern part of the Illinois Basin, where we control through lease and farm-out agreements an aggregate of 135,948 acres of CBM rights. In addition, we continue to look for opportunities to acquire additional CBM acreage rights in the Illinois Basin.

As of July 31, 2007, we have drilled 170 wells. These wells include 111 productive wells, six shut-in wells, 10 plugged wells, four disposal wells, three pressure observation wells, four divested wells, and 32 wells that have been drilled but are not yet in production, including 12 test wells.

Our History

BPI Energy Holdings, Inc. was incorporated under the laws of British Columbia in 1980. Our corporate offices in the United States are located at 30775 Bainbridge Road, Suite 280, Solon, Ohio 44139, telephone (440) 248-4200. Our records office and registered office in Canada is located at 609 Granville Street, Suite 1600, Vancouver, British Columbia V7Y 1C3, telephone (604) 685-8688. Our operations are conducted from an office located in Edwardsville, Illinois.

Beginning in 1996, we had a minority involvement in the Southern Illinois Basin Project. In 2001, Methane Management, Inc. acquired the Southern Illinois Basin Project subject to our minority interest. In August 2001, we acquired Methane Management, Inc. and consolidated 100% of the Southern Illinois Basin Project within BPI. James G. Azlein, President of Methane Management, Inc. at the time, became our President, and we created a new management team. We have since divested all of our assets that are not related to CBM projects in the Illinois Basin.

Recent Developments GasRock Financing

On July 27, 2007, BPI Energy, Inc. (BPI Energy), our wholly owned subsidiary, entered into an Advancing Term Credit Agreement (the Credit Agreement) with GasRock Capital LLC (GasRock). The Credit Agreement provides for an initial commitment to BPI Energy of $10.2 million and the possibility of future advances to BPI Energy of up to an additional $64.8 million. All future advances under the Credit Agreement beyond the initial commitment will be made in GasRock s discretion. BPI Energy has received an initial advance of $9.1 million under the Credit Agreement, which resulted in net proceeds to BPI Energy of $8.2 million after the deduction of GasRock s facility fee, investment banking fees, legal fees and other fees and expenses incurred by BPI Energy in connection with the transaction totaling $0.8 million. The initial advance is expected to be used for continued drilling of development wells at our Southern Illinois Basin Project, drilling of new test wells, pilot projects, possible lease acquisitions and general and administrative expenses.

BPI Energy may request advances under the Credit Agreement at any time before July 25, 2008, which GasRock may in its discretion extend until July 27, 2010. All amounts then outstanding under the Credit Agreement are due and payable on July 25, 2008 (the Loan Termination Date), which GasRock may in its discretion extend until July 29, 2011. 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. BPI Energy is required to make monthly interest payments on the amounts outstanding under the Credit Agreement but is not required to make any principal payments until the Loan Termination Date. BPI Energy may prepay the amounts outstanding under the Credit Agreement at any time without penalty.

BPI Energy is required to pay GasRock a facility fee upon the receipt of any advances under the Credit Agreement in an amount equal to two percent of the amount advanced. BPI Energy is also required to reimburse GasRock for all of the expenses GasRock incurs in connection with entering into and administering the Credit Agreement.

BPI Energy s obligations under the Credit Agreement are secured by a first priority security interest in substantially all of BPI Energy s properties and assets, including all of BPI Energy s CBM rights under its leases, farm-out agreements and fee interests, all of BPI Energy s wells at its Southern Illinois Basin Project, all of BPI Energy s equipment and all of the common stock of BPI Energy (which has been pledged by us). We have provided a guaranty to GasRock of all of BPI Energy s obligations under the Credit Agreement.

Table of Contents

In connection with the execution of the Credit Agreement, BPI Energy granted GasRock a one percent royalty in all CBM produced and saved from BPI Energy s existing leased and owned CBM properties and an additional four percent royalty interest in all CBM produced and saved from BPI Energy s existing wells at its Southern Illinois Basin Project. As long as any of BPI Energy s obligations remain outstanding under the Credit Agreement, BPI Energy will be required to grant the same one percent royalty interest to GasRock on new mineral interests acquired by BPI Energy after July 25, 2008 and the same four percent royalty interest on new wells drilled by BPI Energy that are funded by draws under the Credit Agreement.

The Credit Agreement requires BPI Energy to enter into a swap agreement under which approximately 75% of BPI Energy s proved developed producing reserves scheduled to be produced during a two-year period will be guaranteed a price of not less than $7.00 per MMBtu. Pursuant to this requirement, BPI Energy has initially entered into a 23-month costless collar with BP Corporation North America Inc. (BP) under which BP is required to cover any shortfall below $7.00 per MMBtu that BPI Energy may receive for its CBM production (as determined by a reference market price) as to an aggregate notional amount of 460,000 MMBtu and BPI Energy must pay to BP any amounts above $11.00 per MMBtu that it receives for its CBM production (as determined by a reference market price) as to the notional amount. BPI Energy expects that it will enter into additional hedging arrangements during the next two years to cover the entire 75% of its proved developed producing reserves scheduled to be produced during that period.

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 Credit Agreement contains customary events of default. In addition, GasRock may declare an event of default if, at any time after July 25, 2008, BPI Energy s most recent reserve report indicates that BPI Energy 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 BPI Energy is unable to demonstrate to GasRock s reasonable satisfaction that BPI Energy would be able to satisfy such outstanding amounts through a sale of BPI Energy s assets or equity. Upon the occurrence of an event of default under the Credit Agreement, GasRock may accelerate BPI Energy s obligations under the Credit Agreement. Upon certain events of bankruptcy, BPI Energy s obligations under the Credit Agreement would automatically accelerate. In addition, at any time that an event of default exists under the Credit Agreement, BPI Energy 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 four percent per annum.

Business Strategy

The objectives of our business strategy are to generate growth in gas reserves, production volumes and cash flows at a positive return on invested capital. The principal elements of our business strategy are to:

Explore and Develop Properties. As of July 31, 2007, we have drilled 170 wells. These wells consist of 111 productive wells, six shut-in wells, 10 plugged wells, four disposal wells, three pressure observation wells, four divested wells, and 32 wells that have been drilled but are not yet in production, including 12 test wells. During the 12-month period ending July 31, 2008, we plan to drill between 30 and 70 new wells. This plan contemplates capital expenditures of approximately $10 million to $23 million. The number of wells that we drill during the 12-month period ending July 31, 2008 will be dependent on (i) data obtained from test wells;

(ii) data obtained from our initial pilot wells; (iii) additional financing we are able to secure, including additional advances we are able to make under our Credit Agreement with GasRock; and (iv) the risk factors described in this report.

Become a World Class CBM Exploration and Production Company. We are expanding our technical management team by recruiting and attracting engineers, geologists and production personnel with substantial experience at some of the most successful CBM projects in North America.

Expand CBM Acreage Rights. We continue to look for opportunities to acquire additional CBM acreage rights in the Illinois Basin. Our strategy has been to utilize our test data and all basin-wide data we have been able to access to high-grade areas in the Basin for pilot testing. Successful pilot tests have the potential to lead to future development projects. With this approach in mind, we are acquiring leases and options on acreage blocks in areas where reservoir properties are more favorable and there is currently pipeline delivery infrastructure in place.

Pursue Joint Ventures. We continue to consider joint venture opportunities. With our asset base and technical expertise, we believe that we are well positioned to attract industry joint venture partners for the purpose of providing capital, technical operating expertise and development opportunities to accelerate our growth.

Competitive Strengths

We believe our competitive strengths include the following:

Substantial CBM Acreage Position. The Illinois Basin is one of the few remaining unexploited CBM areas in North America. Because we were the first company to begin acquiring substantial blocks of CBM acreage rights in the Illinois Basin, we have been able to assemble several large contiguous blocks. This substantial footprint should give us opportunities to leverage our knowledge of the Illinois Basin and realize significant economies of scale as our drilling and production activities grow throughout the Illinois Basin.

Demonstrated Commercial Production. We believe that we have taken the initial steps to demonstrate the commercial production capabilities of the Illinois Basin. As of July 31, 2007, we have drilled 170 wells, including 91 productive wells located at our Southern Illinois Basin Project, most of which have not yet reached peak production. We believe that our increasing production at the Southern Illinois Basin Project demonstrates the commercial viability of the Illinois Basin. During our fiscal year ended July 31, 2006 we sold 135,118 Mcf of CBM, and during our fiscal year ended July 31, 2007 we sold 185,305 Mcf of CBM.

Short Drilling Permit Lead Times. We typically experience short turnaround times in obtaining drilling permits as compared to CBM drillers in other CBM basins.

Low Water Disposal Costs. A significant advantage of operating in the Illinois Basin is that we are not required to build costly water disposal facilities. We have disposed of the water we encounter in connection with our drilling and production by re-injecting the water into disposal wells drilled and operated by us.

Substantial Interstate Pipeline Capacity and Low Transportation Costs. A significant advantage that we have over CBM producers in other basins is our proximity to a large number of interstate gas pipelines that have substantial take-away capacity. Because our operations and CBM acreage are located near several large metropolitan gas consuming markets (e.g., Chicago, St. Louis, Nashville, Indianapolis and Detroit) and the fact that many interstate pipelines headed to the East Coast pass through the Illinois Basin, we expect to incur little or no pipeline-related transportation charges. In addition, we do not expect to experience any lost production or sales due to insufficient local or interstate pipeline capacity to transport the CBM that we produce and sell.

Experienced and Incentivized Management and Operating Teams. Our operating team includes individuals that have participated in the drilling or operating of CBM wells in North America since the early 1980s and in the Illinois Basin since 1996. In addition, all of our management team and the majority of our operating employees own common shares of BPI.

CBM Acreage Rights

As of July 31, 2007, our CBM acreage rights, controlled through lease and farm-out agreements and ownership of a CBM estate, include the following:

Project	Developed Acres	Undeveloped Acres	Total Acres(1)
Southern Illinois Basin Project(2)	6,976	3,024	10,000
Northern Illinois Basin Project		366,364	366,364
Western Illinois Basin Project		135,948	135,948
Total	6,976	505,336	512,312

(1) Because we are the exclusive owner of the CBM rights under each of our lease and farm-out agreements, our acreage totals reflect both gross and net acres.

(2) We acquired ownership of the CBM estate covering 10,000 acres in our Southern Illinois Basin Project in a settlement with our former lessor, which is the owner of the coal rights.

Under the terms of the lease agreements pursuant to which we have acquired nearly all of our CBM rights, we are entitled to all of the CBM rights held by our lessors in the counties covered by these agreements. However, we face a number of uncertainties regarding what rights our lessors hold.

The issue of who owns CBM gas, as between the coal rights owner and the oil and gas rights owner, is uncertain in Illinois. Although the appellate court in Illinois for the district where most of our acreage rights are situated has ruled that CBM gas is owned by the coal rights owner, the issue has not been addressed by the highest court in Illinois. We believe, based on advice from legal counsel, that under Illinois law ownership will ultimately be found to lie with the coal rights owner. Based on this advice, we generally secure CBM rights from the coal owners. Some of the lessors from which we have acquired CBM rights may hold both the coal rights and the oil and gas rights for the applicable properties, but in some cases it is not certain that these lessors also hold the oil and gas rights. If any litigation in Illinois concludes that CBM rights lie with the oil and gas owner, we could lose some of our CBM rights.

In addition, in some cases the extent of the coal and/or oil and gas rights held by our lessors is uncertain. We conducted no title or deed examinations prior to executing our lease agreements, and our lessors made no warranties as to the acreage or rights covered by the agreements. Although we have now conducted title and deed examinations covering much of the CBM properties under our leases, these examinations are ongoing at all of our projects. There can be no assurance that our rights under our lease agreements include all of the acreage rights identified in the agreements until title examinations on all of the underlying properties have been completed.

We have been subject to legal complaints regarding the extent of the surface rights that derive from our CBM rights. On occasion, the owners of properties that are adjacent to our drilling locations have challenged our right to cross their property in accessing our drilling locations and our right to lay gas and water flow lines across their property. The extent of our rights in respect of these issues is uncertain in Illinois. If disputes regarding our surface rights are not resolved in our favor, we may be required to acquire surface rights or access our drilling locations and lay gas and water flow lines in inefficient ways, which would cause us to incur increased operating costs. In addition, we could incur significant costs in legal disputes over our surface rights.

Southern Illinois Basin Project

Our CBM rights in the Southern Illinois Basin Project cover 10,000 acres in the southern part of the Illinois Basin. We hold our CBM rights on this acreage pursuant to a purchase agreement under which we acquired the CBM estate in a settlement with our former lessor, the owner of the coal rights. Under the terms of the deed covering this acreage, our right to drill for and produce CBM takes precedence over coal mining operations for as long as CBM is being produced from the acreage. However, the owner of the coal rights has the right to acquire any CBM wells located in these 10,000 acres. If the coal rights owner exercises this option, it will be required to (i) immediately plug any such well so acquired and (ii) pay the fair market value (as established by a mutually agreed upon expert) of such well.

In addition to the GasRock royalties, we are currently paying royalties of 3.03% on our production at this project. The GasRock royalties will also apply to our acreage rights discussed below at the time we produce and sell CBM from the applicable acreage.

We commenced sales of gas from our initial pilot production wells on this project in January 2005. As of July 31, 2007, we have drilled 131 wells at this project. These wells consist of 91 productive wells, six shut-in wells, four divested wells (as a result of the Colt LLC settlement), nine plugged wells, two disposal wells, one pressure observation well, and 18 wells that have been drilled but are not yet in production. Most of the productive wells drilled at this project were initially completed in a limited number of seams, intentionally excluding other seams. Our intention when we drilled these wells was to gather as much geological information as we could about CBM and dewatering characteristics of individual coal seams. During fiscal year 2006, we completed additional seams in most of these wells to begin dewatering and producing CBM from the additional seams penetrated by these wells. During fiscal year 2007, we determined it was beneficial to complete additional seams in the remaining wells, which we plan to begin doing in fiscal year 2008.

All of our proved reserves are currently located at the Southern Illinois Basin Project.

Northern Illinois Basin Project

Our CBM rights in the Northern Illinois Basin Project cover 366,364 acres in Montgomery, Shelby, Christian, Fayette and Macoupin Counties in Illinois, which are located in the north central part of the Illinois Basin. We hold our CBM rights on this acreage pursuant to mineral leases and a farm-out agreement.

We have entered into a lease agreement with Montgomery County covering 133,788 acres of CBM rights in Montgomery County, Illinois. The lease agreement extends until November 27, 2010. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage. Under the lease agreement, we are required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage.

We have also entered into a lease agreement with Shelby County covering 63,250 acres of CBM rights in Shelby County, Illinois. The lease agreement extends until November 12, 2008. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage, with each productive vertical well holding 320 acres and each productive horizontal well holding 1,920 acres. We are required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage.

We have also entered into a lease agreement with IEC (Montgomery), LLC covering 102,000 acres of CBM rights in Christian, Fayette, Montgomery and Shelby Counties in Illinois. The lease agreement extends until April 26, 2026. After the initial term of the agreement, we can continue to hold the lease as to each acreage block where we are producing CBM in commercial quantities. We are required to pay royalties to the lessor on our gross proceeds from the sale of CBM produced from the covered acreage at rates ranging up to 12.5%. We have also entered into a lease agreement with Christian Coal Holdings, LLC covering 12,040 acres of CBM rights in Christian and Montgomery Counties in Illinois. The lease agreement extends until April 26, 2026. After the initial term of the agreement, we can continue to hold the lease as to each acreage block where we are producing CBM in commercial quantities. We are required to pay royalties to the lessor on our gross proceeds from the sale of CBM produced from the covered acreage at a rate of 12.5%. As discussed in Item 3 below, these lease agreements with IEC (Montgomery), LLC and Christian Coal Holdings, LLC are currently subject to litigation.

We have also entered into a lease agreement with Christian County to lease 14,033 acres of CBM rights in Christian County, Illinois. The lease agreement extends until January 20, 2012. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage. Under the lease agreement, we are required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage.

Under the lease agreements with Montgomery, Shelby and Christian Counties, our right to drill for and produce CBM is expressly subject to the mining of coal on the covered acreage. We may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining operations will be undertaken.

Under the lease agreements with IEC (Montgomery), LLC and Christian Coal Holdings, LLC, any drilling operations that we set-up can be displaced by coal mining operations. However, the lessor is required to provide us with a mine plan for the leased acreage indicating the acreage blocks that the lessor plans to mine and the order of priority for the acreage blocks that it plans to mine. If the lessor displaces a well ahead of the schedule outlined in the mine plan, the lessor may be required to reimburse us for the cost of plugging the well and, depending on how long the well has been in production and the cumulative gross income generated by the well, the value of the CBM that could be recovered from the well in the remainder of an eight-year term.

Also included in the Northern Illinois Basin Project are 41,253 acres of CBM rights in Macoupin County, Illinois, which we can earn under a farm-out agreement with Addington Exploration, LLC, as described below.

As of July 31, 2006, we completed drilling a 10-well pilot program at this project that we refer to as the Shelby Pilot. In fiscal year 2007 at the Shelby Pilot, we added one pressure observation well and drilled two additional producers that are not currently completed. Also in fiscal year 2007, we drilled two new test wells in other parts of the Shelby County acreage block. During the fourth quarter of fiscal year 2007, we announced our decision to continue production activities at our Shelby Pilot, while deferring additional development pending further production and pressure information.

As of July 31, 2007, we drilled and completed a second 10-well pilot project, the Macoupin Pilot, in the Northern Illinois Basin Project. Those wells have just started the dewatering process. The Macoupin Pilot also includes one pressure observation well and one disposal well.

We currently have no proved reserves located at the Northern Illinois Basin Project.

Western Illinois Basin Project

Our CBM rights in the Western Illinois Basin Project cover 135,948 acres in Clinton, Washington, Marion and Perry Counties in Illinois, which are located in the northwestern part of the Illinois Basin. We hold our CBM rights on this acreage pursuant to mineral leases and a farm-out agreement.

We have entered into a lease agreement with Clinton County covering 55,900 acres of CBM rights in Clinton County, Illinois. The lease agreement extends until October 24, 2010. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage. Under the lease agreement, we are required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage.

We have also entered into a lease agreement with Washington County covering 39,169 acres of CBM rights in Washington County, Illinois. The lease agreement extends until September 9, 2011. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage, with each productive vertical well holding 320 acres and each productive horizontal well holding 1,920 acres. We are required to pay royalties to the lessor from our gross proceeds from the sale of CBM produced from the covered acreage. The royalty is equal to 12.5% or 6.25% of our gross proceeds, depending on whether it is determined that Washington County s CBM rights, if any, are derived from coal rights or oil and gas rights.

We have also entered into a lease agreement with Marion County covering 17,882 acres of CBM rights in Marion County, Illinois. The lease agreement extends until June 7, 2012. After the initial term of the agreement, we can continue to hold the lease as long as we are producing CBM from the covered acreage. Under the lease agreement, we will be required to pay royalties to the lessor equal to 12.5% of our gross proceeds from the sale of CBM produced from the covered acreage. If we do not commence exploration of CBM within one year from the commencement of the lease, we will be required to pay advance royalties to the lessor equal to $8,941 for each one-year period that we delay commencing exploration. Any payment of advance royalties can be credited against royalties that may later become payable to the lessor from our production of CBM.

Under the lease agreements with Washington and Marion Counties, our right to drill for and produce CBM is expressly subject to the mining of coal on the covered acreage. We may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining

Table of Contents

operations will be undertaken. Under the lease agreement with Clinton County, coal mining rights granted to third parties do not take precedence over our CBM operations.

Also included in the Western Illinois Basin Project are 22,997 acres in Perry County, Illinois, which we can earn under a farm-out agreement with Addington Exploration, LLC, as described below.

As of July 31, 2007, we have drilled four test wells at the Western Illinois Basin Project from which we are still gathering and evaluating data. We currently have no proved reserves located at the Western Illinois Basin Project.

Farm-out Agreement with Addington Exploration, LLC

We have entered into a farm-out agreement with Addington Exploration, LLC covering 41,253 acres of CBM rights in Macoupin County, Illinois (part of our Northern Illinois Basin Project) and 22,997 acres of CBM rights in Perry County, Illinois (part of our Western Illinois Basin Project) that Addington controls pursuant to coal seam gas leases. The farm-out agreement provides for an initial 36-month evaluation period, during which we may test and evaluate the covered properties. The evaluation period can be extended by us on unearned acreage through the payment of a fee equal to $0.50 per acre, increasing over five years to $2.50 per acre. For each vertical and horizontal well that we place into production during the term of the agreement, Addington will assign to us its CBM rights covering the surrounding 160 acres penetrated by one of our wells. We plan to extend the 36-month evaluation period on unearned acreage when it expires in November 2007.

We are required to pay Addington a royalty equal to 3% of our proceeds from the sale of CBM produced from the covered acreage. In addition, we must pay royalties totaling 12.5% to the lessors under the coal seam gas leases underlying this farm-out agreement.

As discussed in Item 3 below, our farm-out agreement with Addington is currently subject to litigation.

Technical Services Agreement with BHP Billiton

Our Technical Services Agreement with BHP Petroleum (Exploration) Inc., a wholly owned subsidiary of BHP Billiton, expired at the end of its term on September 30, 2006, and BHP did not exercise its right to extend the agreement. BHP s right of first refusal to acquire us lapsed as of the expiration date of the agreement, and the 4 million stock appreciation rights that we granted to BHP, which could be exercised by BHP only in connection with an acquisition of us, expired on March 30, 2007.

Status of CBM Operations

The following table summarizes the status of wells we have drilled as of July 31, 2007:

		Nonproductive Wells						
Project	**Productive Wells**	**Drilled Not Yet Completed(1)**	**Shut-in(2)**	**Plugged**	**Pressure Observation(3)**	**Disposal**	**Divested(4)**	**Total**
Southern Illinois Basin Project	91	18	6	9	1	2	4	131
Northern Illinois Basin Project	20	10		1	2	2		35

Western Illinois Basin Project		4						4
Total	111	32	6	10	3	4	4	170

(1) Wells drilled not yet completed includes 18 wells drilled but not yet completed at our Southern Illinois Basin Project, four test wells at our Western Illinois Basin Project, two wells drilled but not yet completed at our Shelby Pilot project, and eight test wells at our Northern Illinois Basin Project.

(2) Shut-in wells include six coal mine methane wells at our Southern Illinois Basin Project.

(3) Pressure observation wells are non-producing wells that are used to measure seam-by-seam pressures within the drainage pattern of our CBM fields.

(4) Under the terms of the Colt LLC settlement, we divested our ownership interests in four wells.

Table of Contents

The following table sets forth our drilling activities over the last three fiscal years:

	Fiscal Year Ended July 31, 2007	2006	2005
Exploratory Wells(1):			
Productive(2)	10	10	
Nonproductive(3)	12	4	3
Total	22	14	3
Development Wells(1):			
Productive(2)	5	49	37
Nonproductive(3)	18	5	17
Total	23	54	54
Total Wells:			
Productive(2)	15	59	37
Nonproductive(3)	30	9	20
Total	45	68	57

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered CBM reservoir, or to greatly extend the known limits of a previously discovered reservoir. A development well is a well drilled within the presently proved productive area of a CBM reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

(2) A productive well is an exploratory or development well that has been completed and is tied into our gas and/or dewatering system. A productive well may produce only water for a period of time before gas begins to flow through the gas gathering system.

(3) A nonproductive well is an exploratory or development well that is not currently a producing well, including pressure observation wells, disposals wells, test wells, and wells drilled but not yet completed.

As of July 31, 2007, all of the wells that we have drilled are vertical wells. We estimate that a typical vertical well will require about 24 to 48 months to reach peak production. We completed most of our productive wells in a limited number of seams, intentionally excluding other seams. Our intention when we drilled these wells was to gather as much geological information as we could about CBM and dewatering characteristics of individual coal seams. During our 2006 fiscal year, we went back and completed additional seams in most of these wells to begin dewatering and producing CBM from the additional seams penetrated by these wells. During fiscal year 2007, we determined it was beneficial to complete additional seams in the remaining wells, which we will begin doing in fiscal year 2008. We began selling gas from our first productive wells in January 2005. As of July 31, 2007, we believe that most of our productive wells have not yet reached peak production. Although we have drilled wells on only a relatively small part of our acreage, we have not to date determined that any well we have drilled is a dry hole.

Production and Sales

The following table sets forth our net sales volume for the periods indicated.

	Twelve Months Ended July 31,		
	2007(1)	**2006(1)**	**2005(1)(2)**
Total net sales (Mcf)	185,305	135,118	17,885

(1) Total sales volumes omit (i) gas consumed in operations and (ii) gas sales equivalent to royalty interests held by our various lessors.

(2) No gas was produced until January 2005.

Table of Contents

Average Sales Prices and Production Costs

The following table sets forth the average sales price and average production costs for all of our gas production for the periods indicated.

	Twelve Months Ended July 31,		
	2007	**2006**	**2005**
Average net gas sales price (per Mcf)	$ 6.50	$ 8.34	$ 6.59
Average net production cost (per Mcf)(1)	8.68	7.18	17.18

(1) Production costs include a significant amount of fixed expenses required to operate a minimum number of our wells. As the number of wells and production increase, these costs are expected to decrease on a per unit basis as they are spread over a greater amount of production.

Reserves

Proved reserves are the estimated quantities that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements (of which none existed as of July 31, 2005, 2006 and 2007, the dates of our estimates of proved reserves prepared by our independent reservoir engineer consultant, Schlumberger Data & Consulting Services), but not on escalations based on future conditions. We did not file any reserve information with any other federal authority or agency during the fiscal year ended July 31, 2007. The following table shows our estimated proved developed and proved undeveloped reserves. Reserve information is net of our royalty obligations. Proved developed and proved undeveloped reserves are reserves that could be commercially recovered under current economic conditions, operating methods and government regulations. Proved developed and undeveloped reserves are defined by SEC Rule 4-10(a)(2) of Regulation S-X.

	Net Reserves (MMcf) As of July 31,		
	2007	**2006**	**2005**
Estimated proved developed reserves	10,639	8,983	2,971
Estimated proved undeveloped reserves	5,635	5,735	7,321
Total estimated proved developed and undeveloped reserves	16,274	14,718	10,292

Since July 31, 2007 we have completed and tied in 10 wells previously classified as proved undeveloped and representing 1,342 MMcf in Schlumberger s reserve report. In addition, since July 31, 2007 we have drilled, completed and tied in three wells representing 403 MMcf that are not included as proved reserves in Schlumberger s reserve report as of July 31, 2007.

Discounted Future Cash Flows

The following table shows our standardized measure of discounted future net cash flows, based on our estimated proved developed and undeveloped reserves (discounted at a rate of 10%), net of taxes:

	As of July 31,		
	2007	**2006**	**2005**
		(Dollars in thousands, except per unit amounts)	
Total standardized measure of discounted future net cash flows	$ 17,183	$ 32,734	$ 23,068
Prices used in calculating reserves (per Mcf)	5.29	7.22	7.44

Sales and Distribution of our Gas

Our current and future plans anticipate that we will sell all of our CBM to either (i) pipeline companies or (ii) natural gas marketing companies that secure space on pipelines. There are multiple pipeline and gas marketing

Table of Contents

companies we could choose to deal with in selling our CBM. There are multiple interstate and intrastate pipeline companies that have pipelines that cross or are in close proximity to all of our current acreage in the Illinois Basin. The interstate pipelines include lines owned by Texas Eastern, Northern Borders, NGPL and Ameren. These pipelines are available to the marketing companies to whom we anticipate selling CBM. We believe that these marketing companies will have adequate capacity from the existing pipelines in the Illinois Basin to be able to purchase all of the CBM we anticipate producing and selling within the next three to five years.

We currently sell all of our CBM production to one gas marketing company, Atmos Energy Marketing, LLC, pursuant to monthly contracts. Under these monthly contracts, Atmos is required to buy all of our CBM production, up to a maximum of 2,500 MMBtus per day (which equates to approximately three times our current daily production), at the NYMEX (New York Mercantile Exchange) price as of the close of business on the last day of the most recently ended month less 25 cents per MMBtu as a marketing charge. If we are unable to extend our monthly contracts with Atmos, we believe that we will have multiple gas marketing companies available to us for the sale of our CBM production.

On July 31, 2007, pursuant to requirements in our Credit Agreement with GasRock, we entered into a 23-month costless collar with BP for the notional amount of 20,000 MMBtu per month beginning in September 1, 2007. For a more detailed description of this arrangement, see the discussion under Item 7A of Part II below.

We currently have no fixed price contracts for the sale of our CBM. We do not anticipate entering into any fixed price contracts for the sale of our CBM during the next 24 months. We will reevaluate the risks and benefits of entering into fixed price contracts after our projects and wells become more mature.

Availability of Drilling Equipment and Personnel

We utilize drilling contractors to perform all of the drilling on our projects. We maintain a limited number of supervisory and field personnel to oversee drilling and production operations. Our plans to drill additional wells are determined in large part by the anticipated availability of acceptable drilling equipment and crews. We believe that sufficient drilling equipment and crews will be available to us in the Illinois Basin to achieve our drilling plan for fiscal year 2008. However, we do not currently have any contractual commitments with drilling contractors, and we can provide no assurance that we will have adequate drilling equipment or crews to achieve our drilling plans.

Governmental Regulations

Our business is affected by numerous laws and regulations, including those relating to energy, the environment and conservation. Failure to comply with these laws and regulations may result in increased compliance costs and the assessment of administrative, civil or criminal penalties and/or the imposition of injunctive relief. Changes in any of these laws and regulations could have a material adverse effect on our business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

We believe that our current operations comply in all material respects with applicable laws and regulations, and that they have no more restrictive effect on us than on other similar companies in the energy industry.

The following discussion describes certain laws and regulations that apply to us and is qualified in its entirety by the foregoing.

State Regulations

Our operations are subject to regulation at the state level and, in some cases, county, municipal and local governmental levels. Such regulation includes:

- requiring permits for the drilling of wells;
- maintaining bonding requirements to drill or operate wells;
- regulating the location of wells, the method of drilling and casing wells, surface use and the restoration of properties upon which wells are drilled; and
- regulating the plugging and abandoning of wells and the disposal of fluids used and produced in connection with operations.

Our operations are also subject to various conservation laws and regulations relating to well spacing and safety issues for gas gathering systems.

Environmental Regulations

We are subject to extensive federal, state and local environmental laws and regulations that, among other things, regulate the discharge or disposal of substances into the environment and otherwise are intended to protect the environment. Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial administrative, civil and/or criminal penalties and, in some cases, injunctive relief for failure to comply. Some laws and regulations relating to the protection of the environment may, in certain circumstances, impose strict liability for environmental contamination. Other laws and regulations may impose restrictions that prevent the rate of natural gas production from being economically optimal or restrict or prohibit exploration or production activities in environmentally sensitive areas. In addition, state laws often require some form of remedial action such as the closure of inactive pits and the plugging of abandoned wells to prevent pollution from former or suspended operations.

We believe that we are in substantial compliance with current applicable laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us. However, from time to time, legislation or other initiatives are proposed to place more onerous conditions on our operations. Adoption of any such proposals could adversely impact our operating costs, capital expenditures, earnings or competitive position.

Our CBM operations require the hydraulic fracturing of coal seams. We believe that this technique is in compliance with applicable laws and regulations, but neither the Illinois Department of Natural Resources Office of Mines and Minerals nor the U.S. Environmental Protection Agency regulates the hydraulic fracturing of coal bed formations as a form of underground injection. It is possible that the hydraulic fracturing of coal beds for CBM production will become regulated within the United States as a form of underground injection, resulting in the imposition of stricter performance standards, which, if not met, could result in diminished opportunities for CBM production enhancement and increased administrative and operating costs.

In CBM production, naturally occurring groundwater is pumped to the surface as a by-product. We currently dispose of water from our wells through water flow lines that re-inject the water into water disposal wells. Discharge of this water is subject to federal and local regulation, and we are required to obtain permits from the State of Illinois to re-inject the water that our wells produce. We have received permits from the State of Illinois that allow us to dispose of all the water that we anticipate producing at both our Southern Illinois Basin Project and Northern Illinois Basin Project during the fiscal year 2007. As we drill additional wells in areas not currently serviced by our existing water disposal wells, we believe that we will be able to obtain the necessary permits for additional disposal wells, although we can make no assurance in this regard. If the water produced from our wells increases substantially and/or the water quality falls below acceptable standards, other disposal or treatment methods may be required to be implemented.

Competition

We operate in the highly competitive natural gas market. We face competition from other companies in each of the following areas:

- acquiring CBM acreage rights;
- selling our natural gas production;

- identifying and employing new technologies; and

- acquiring the equipment, expertise and personnel necessary to develop and operate our properties.

Many of our competitors have financial, technological and other resources that are greater than ours. These companies may be able to pay more for CBM acreage rights and exploratory prospects and may be able to evaluate and purchase more acreage rights and prospects than our resources permit. To the extent our competitors are able to pay more for properties, technologies, equipment and qualified personnel than we are, we will be at a competitive disadvantage. In addition, many of our competitors may enjoy technological advantages and may be able to identify, develop or implement new technologies more rapidly than we can. Our ability to acquire additional acreage rights and explore for CBM prospects in the future will depend upon our ability to obtain the necessary equipment, attract and retain and qualified personnel, successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this competitive environment.

Employees

As of July 31, 2007, we have 21 full-time employees, including our executive officers. We utilize independent consultants and contractors to perform various professional services and for drilling, testing and completion work.

Executive Officers and Directors

Name	Age	Position
James G. Azlein	58	President, Chief Executive Officer and Director
James E. Craddock	48	Chief Operating Officer and Director
Randy L. Elkins	41	Controller and Acting Chief Financial Officer
Dennis Carlton	57	Director
David E. Preng	61	Director
Costa Vrisakis	73	Director

James G. Azlein has been President, Chief Executive Officer and a Director since August 23, 2001. From 1979 to 1998, Mr. Azlein held positions including President and Chief Financial Officer and was a principal of Cyrus Eaton Group (CEG), a private company that specialized in project development, including securing technologies, management, financing and marketing for a variety of projects, for hotels and resorts, agricultural projects and manufacturing plants. In early 2000, Mr. Azlein formed Methane Management, Inc. to acquire the interest of various partners in a 43,000 acre CBM project in southern Illinois in which we owned a minority interest. In August 2001, we acquired Methane Management, Inc. and Mr. Azlein became our President. He has assembled a new management team and is guiding our transition from a primary focus on property acquisition to one of CBM development in the Illinois Basin.

James E. Craddock has been Chief Operating Officer since December 19, 2006 and a Director since January 30, 2007. He previously served as our Senior Vice President of Operations. He oversees all of our operational activities, including engineering, geology and land management activities. In particular, he is integrally involved in planning and managing all aspects of our CBM exploration, drilling and production activities. Mr. Craddock joined us from Houston-based Burlington Resources Inc. (acquired by ConocoPhillips on March 31, 2006), where he served as Chief Engineer. In this, his most recent capacity with Burlington, he was responsible for reserve estimation, corporate operations, recruitment and development of the engineering staff and growth of a technical center. As Director of Strategic Planning at Burlington, Mr. Craddock was involved in Burlington s $3 billion acquisition of the Louisiana Land & Exploration Company (LL&E). He was also involved in developing Burlington s Farmington, New Mexico CBM project. As head of Reservoir Engineering, and later as Engineering Manager, he was responsible for leading the technical team that grew the Fruitland CBM Project to over 400 MMcf per day. During the play s peak level of activity, this required drilling up to 300 new CBM wells per year, conducting up to 100 recompletions per year and participating in 100 non-operated wells each year. He began his career in 1981 with Superior Oil (later Mobil) upon graduating from Texas A&M University with a Bachelor of Science in Mechanical Engineering.

Randy L. Elkins assumed the position of Acting Chief Financial Officer in October 2006, and has been Controller since February 2005. He is a Certified Public Accountant with more than 15 years of experience in accounting and auditing. Prior to joining us, Mr. Elkins held a senior finance position with International Steel Group, Inc. (NYSE: ISG). From January 1992 through September 2004, he served in various increasingly responsible positions with Ernst & Young LLP, most recently as a senior manager in its Transaction Support Group. While at E&Y, he focused on audits of SEC public companies, mergers and acquisitions and bankruptcy restructurings. Mr. Elkins earned his Bachelor of Business Administration in Accounting from Cleveland State University. He is a member of the Ohio Society of Certified Accountants.

Table of Contents

Dennis Carlton has been a Director since May 2005. Mr. Carlton has been involved in CBM since 1989. From 1995 through September 2004, he served as a director and worked in several senior executive positions with Evergreen Resources, Inc., serving most recently as Executive Vice President, Exploration and Chief Operating Officer, as well as President of Evergreen Operating Corp. His primary responsibilities included management of all geoscience, engineering, land matters and domestic and international business development activities. Since October 2004, when Evergreen was acquired by Pioneer Natural Resources, Inc., Mr. Carlton has served as a technical and business advisor to Pioneer s Western Division. Prior to joining Evergreen, he held positions in several companies including Mobil Oil Corporation. Mr. Carlton s career and knowledge base in CBM spans a vast geographic area including the Rocky Mountain Basins, Mid-Continent, United Kingdom and Alaska. His efforts in the Raton Basin with Evergreen were recognized when he was named the Rocky Mountain Association of Geologists Outstanding Explorer in 2000.

David E. Preng has been a Director since February 2006. Mr. Preng is the president of Preng & Associates, an executive recruiting company he founded in 1980. Preng & Associates focuses exclusively on matching senior-level business executives seeking board of director, chief executive and other upper-level assignments with energy and natural resources companies in both the United States and Europe. Mr. Preng, who has managed numerous global engagements for a variety of multinational clients, coordinates Preng & Associates worldwide practice and is directly responsible for Russian, CIS and Far East recruiting in North America. Prior to founding Preng & Associates, he spent six years in the executive search industry. His industry background includes financial, managerial and executive positions with Shell Oil Company, Litton Industries and Southwest Industries. Mr. Preng earned his Bachelor of Science from Marquette University and his MBA from DePaul University. From 1997 to 2006, he was a director of Remington Oil and Gas, where, in addition to chairing its Nomination & Governance Committee, he served as lead independent director and as a Compensation Committee member. During his tenure on Remington s board, Remington was acquired by Cal Dive International, Inc. Mr. Preng also serves on the board of directors of Maverick Oil & Gas, Inc., where he chairs its Compensation Committee. He is a director of Community National Bank, the Houston Chapter of the National Association of Corporate Directors and a member of Texas A&M s International Board. Additionally, he is a fellow of the Institute of Directors in London and has served three terms as director and two years as president of the British American Business Council.

Costa Vrisakis has been a Director since January 2002. Mr. Vrisakis is a financier and entrepreneur based in Sydney, Australia. He has been a founder and director of several Sydney Stock Exchange-listed companies. One of his former ventures includes a printing company, Snap-Apart Pty. Ltd., which Mr. Vrisakis founded along with two employees in 1959. In 1985, Snap-Apart Pty. Ltd. was listed on the Sydney Stock Exchange under the name Computer Resources Ltd. In 1993, Moore Corp. of Toronto, Canada acquired Computer Resources. Since 1985, when Mr. Vrisakis sold his interest in Computer Resources Ltd., he has focused his attention on various real estate projects and stock market investments. Since 2000 through the present time, Mr. Vrisakis has devoted the majority of his time to managing his 50% interest in three hotels in Sydney, Australia.

William J. Centa served as a Director from March 2005 until his resignation on September 13, 2007.

Significant Employees

The following persons are not executive officers but make significant contributions to our business:

Randy Oestreich, 51, has been Vice President of Field Operations since March 2005. Mr. Oestreich owns A-Strike Consulting, a private consulting company formed in April 2003 to provide consulting services to the CBM industry. From 1976 to 2003, Mr. Oestreich worked for Halliburton Energy Services. With Halliburton, Mr. Oestreich worked in conventional oil and gas exploration and development, as well as unconventional gas, including CBM, primarily in the Illinois Basin, but also in Michigan, Ohio, Kentucky, Pennsylvania and West Virginia. In addition, he was a member of Halliburton s Coalbed Methane Solutions Team. For the past 15 years, his work has focused on CBM, mine methane and New Albany shale exploration and development. Mr. Oestreich has worked on, and is familiar with, the majority of unconventional gas projects that have been initiated in the Illinois Basin and has worked on the Southern Illinois Basin Project since its inception.

Dan Anderson, 60, has been Director of Property Acquisitions since January 2002. Mr. Anderson has more than 30 years of oil and gas and real estate experience: from 1976 to 1983 as Land Department Manager with John Carey Oil

Table of Contents

Company, Inc.; from 1983 to 1989 as president of his own oil and gas investment consulting company; and as President of a private real estate development company, DAPA Investments, Inc. Prior to joining us, Mr. Anderson worked with DeMier Oil in securing oil, gas and CBM leases in central and southern Illinois, as well as pipeline right-of-way easements. He has extensive experience in the oil, gas and CBM business in the Illinois Basin, including oil and gas and CBM leasing terms and agreements. In addition, he has extensive experience in the workings of land title and registrar procedures on both a local and state level. Mr. Anderson is a member of the Illinois Oil and Gas Association and the American Association of Professional Landmen.

Michael Dawson, 57, has been Senior Geological Advisor since August 2006. He was most recently with Burlington Resources Inc. (acquired by ConocoPhillips on March 31, 2006) as a petroleum geologist. During his 26-year tenure with Burlington, he was involved in various exploration and exploitation projects. At Burlington s Farmington, New Mexico office, he was involved in the Fruitland CBM play. Most recently, Mr. Dawson helped design and implement a comprehensive (San Juan Basin) Pictured Cliffs Sandstone reservoir optimization program. Previously, he worked in Burlington s Amarillo and Houston offices where his responsibilities included prospect generation, wellsite geology, field development and economic analysis for projects in the Anadarko, Arkoma and other basins. Mr. Dawson began his career in 1978 with Conoco (now ConocoPhillips) upon graduating with a Master of Science in Geology from San Diego State University. He earned his Bachelor of Science in Geology from the University of Michigan.

James Erlandson, 32, also formerly of Burlington Resources, has been Senior Staff Reservoir Engineer since August 2006. Previously, he was team leader of the Kaybob Resource Assessment Team working in Calgary, Alberta, with responsibility for analyzing and developing regional unconventional gas plays in British Columbia and Alberta. As Mr. Erlandson progressed through assignments of increasing responsibility with Burlington, he was involved in strategic planning, acquisitions and exploitation of unconventional sand and CBM plays. He was also involved in the addition of proven gas reserves in the Western Canada Sedimentary Basin, infill program analysis and development, and the optimization of Fruitland coal wells in the San Juan Basin. Mr. Erlandson began his career in 1997 as a production engineer with Marathon Oil Company after graduating with honors from Montana Tech, where he earned his Bachelor of Science in Petroleum Engineering.

Kelly Sutton, 30, has been Senior Staff Engineer since September 2006. Ms. Sutton was previously with Energen Resources, where she served as a reservoir/acquisitions engineer. While at Energen, she evaluated CBM properties in the Powder River, San Juan and Black Warrior Basins, oil properties in the Permian Basin and tight gas properties in East Texas and Northern Louisiana. Prior to Energen, she served in various reservoir and production engineering positions with Burlington Resources and Phillips Petroleum. Ms. Sutton received her Bachelor of Science in Chemical Engineering from the University of Alabama.

Bradford Sutton, 33, has been Senior Staff Engineer since September 2006. Mr. Sutton was previously with Energen Resources, where he focused on CBM and tight gas development in the San Juan Basin. Prior to joining Energen, Mr. Sutton was a production engineer at Burlington Resources. During his career, he has worked on CBM development in the San Juan and Powder River Basins and conventional gas and tertiary oil development in the Permian Basin. He holds a Bachelor of Science in Petroleum Engineering from the University of Alabama.

Internet Website

We are required to file annual, quarterly and other reports and proxy statements with the SEC. Our SEC filings are available to the public over the internet at the SEC s website at *www.sec.gov* or from our website at *www.bpi-energy.com.* You may also read and copy any documents that we file at the SEC s public reference room located at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operations of the public reference room. In addition, we make available free of charge through our internet website our annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Additionally, charters for the committees of our Board of Directors and our Code of Business Conduct and Ethics can be found at our website under the heading Highlights on the Corporate Governance page. Shareholders may request copies of these documents by writing to our Investor Relations Department at 30775 Bainbridge Road, Suite 280, Solon, Ohio 44139.

Table of Contents

ITEM 1A. *Risk Factors.*

You should be aware that the occurrence of any of the events described in this Risk Factors section or elsewhere in this report could have a material adverse effect on our business, financial position, results of operations and cash flows. In evaluating us, you should consider carefully, among other things, the factors and specific risks set forth below, and in documents we incorporate by reference.

Our current revenues are minimal and not sufficient to support our operations. If we are unable to raise additional financing, we may not be able to carry out our long-term plans.

The wells that we have drilled began producing CBM for sale only in January 2005, and the amount of CBM that we are currently selling is not significant. We are not currently generating net income or positive cash flow from operations. 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 CBM rights. Our Credit Agreement with GasRock provides for an initial commitment of $10.2 million, of which we have drawn $9.1 million. Additional advances beyond the initial $10.2 million commitment are at GasRock s discretion. Therefore, in order to achieve our long-term plans and maintain a viable business, we will need to raise additional financing, either by convincing GasRock to advance additional funds or obtaining financing from new sources. If we are unable to raise additional financing, we will likely be unable to carry out our long-term plans, which would negatively impact the value of your investment in us.

Even if we continue to demonstrate the commercial viability of CBM wells in the Illinois Basin, we may encounter difficulty in raising additional capital on favorable terms. Interest rates and investor expectations and demands are subject to change, and any change in these areas could have a negative effect on the financing terms that we are able to obtain. In addition, the terms of any new financing may adversely affect your investment. If we issue shares of preferred stock or additional common shares, institutional investors may negotiate terms equal to or more favorable than market prices or the terms of our prior offerings, resulting in dilution to existing shareholders. As with our current GasRock financing, debt financing could result in the lenders having a claim to assets prior to the rights of our shareholders, divert cash flow to service the debt, and restrict operations through compliance with lenders restrictions. Any such terms could adversely affect the return that you receive on your investment in us.

We have incurred significant operating losses since our inception and may not achieve profitability in the future.

We have experienced significant operating losses and negative cash flow from operations since our inception, and we currently have an accumulated deficit. During our fiscal year ended July 31, 2006 we incurred a net loss of $8,836,244, and during our fiscal year ended July 31, 2007 we incurred a net loss of $20,640,488. As of July 31, 2007, we have an accumulated deficit of $47,834,016. We anticipate that our operating costs and capital expenditures will continue to grow as we continue to explore and develop our CBM rights. Even if we significantly grow our revenues from the sale of CBM, it is possible that our increased operating costs and capital expenditures will prevent us from generating net income. In addition, in the future we could incur greater than expected drilling or other operating expenses, we could discover that our properties are not commercially viable, or gas prices could decline significantly. Any of these events would have a significantly negative impact on our ability to generate net income. If we are unable to achieve profitability at any time in the near future, the value of your investment in us could be adversely affected.

CBM exploration is speculative in nature and may not result in operating revenues or profits.

The Illinois Basin is largely untested for commercial CBM production. In addition, we have evaluated the CBM potential in only a relatively small part of our acreage rights. Only an extended production history of the wells that we drill will indicate whether our wells will be commercially productive over the long-term. We could determine in the future that the Illinois Basin does not contain enough CBM for commercially viable operations, or that the conditions in the Illinois Basin are not conducive for commercially viable operations. Any such determination would have a significantly negative effect on your investment in us.

Table of Contents

Future wells that we drill may not be successful, due to low CBM content in the coal, low permeability, unusually low or high water quantities, low water quality, incorrect forecasts or other factors. We cannot be sure that completed wells will produce enough CBM to recover our capital investments. We can provide no assurance that the exploration and development of our projects will occur as scheduled, or that actual results will be in line with expectations.

The cost of drilling, completing and operating wells is often uncertain. Factors that can delay or prevent drilling operations, include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- shortages or delays in the availability of drilling rigs or the delivery of equipment;
- the inability to hire personnel or engage other third parties for drilling and completion services;
- the inability to obtain regulatory approvals to drill CBM wells where planned;
- litigation initiated by surface owners attempting to prevent us from utilizing the surface land for our operations; and
- the inability to sell CBM production, due to the loss of access to the pipelines into which CBM production is sold or an oversupply of natural gas in the market.

Wells on some projects could require substantial dewatering ahead of production, which could delay the start of production by months and increase completion costs. Continued high volume water pumping during production would increase operating costs. If we experience significant setbacks in drilling, completing and operating wells, or significantly increased costs due to unexpected conditions, our financial performance will suffer.

Any decline in natural gas prices could negatively impact our ability to attain profitable operations.

Our ability to grow our revenues, and ultimately attain profitable operations, will depend not only on our ability to place CBM wells into production but also on the market for natural gas. Natural gas prices have historically been volatile, and they are likely to continue to be volatile in the future. If natural gas prices decline significantly for extended periods of time, the CBM wells that we place into production may not be commercially viable and we might not be able to generate enough revenues to reach profitable operations. Our failure to reach profitable operations would negatively affect the value of your investment in us.

If we are unable to repay or refinance the amounts advanced to us by GasRock when they become due, GasRock could enforce its security interest in our assets.

The obligations under our Credit Agreement with GasRock are due and payable on July 25, 2008, unless GasRock extends this due date. In addition, if we default under the Credit Agreement, such as by breaching a restrictive covenant or one of the other provisions of the agreement, GasRock could accelerate the due date of our obligations. BPI Energy s obligations under the Credit Agreement are secured by a first priority security interest in substantially all of BPI Energy s properties and assets, including all of our CBM acreage rights and all of our wells at our Southern Illinois Basin Project. If we are unable to repay or refinance the amounts advanced to us by GasRock when they become due, GasRock could enforce its security interest in our assets. If GasRock took such action, the value of your investment in us would be significantly and adversely affected.

The limits imposed on our subsidiary BPI Energy in our Credit Agreement with GasRock could prevent us from acquiring additional acreage or completing joint ventures or cause us to lose access to the facility.

Our Credit Agreement with GasRock imposes various restrictive covenants on our subsidiary BPI Energy, including limitations on its ability to effect mergers or acquisitions and make investments. In addition, 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. If BPI Energy fails to maintain these ratios a default under the Credit Agreement could result. Such a default would permit GasRock to accelerate the due date of our obligations and deny us access to further advances. BPI Energy s compliance with these restrictive covenants and ratios could also prevent us from acquiring additional acreage or entering into joint ventures or other strategic transactions. If BPI Energy s compliance with these provisions overly restricts our business activities, or its breach of such provisions causes us to lose access to the facility, our business and your investment in us could be adversely affected.

Our hedging transactions may limit our potential gains or expose us to losses.

Under the terms of our Credit Agreement with GasRock, we are required to hedge at least 75% of projected production from our proved developed producing properties. These transactions could limit our potential gains if natural gas prices were to rise substantially over the prices established by the contracts. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- the counterparties to our contracts fail to perform under the contracts; or
- our production costs on the contracted production significantly increase.

The financial loss resulting from any of these events could be significant in relation to our revenues and cash balances, which could have a significantly negative effect on our business.

We could experience delays in securing drilling equipment and crews, which would cause us to fail to meet our drilling plans and negatively impact our operations.

We utilize drilling contractors to perform all of the drilling on our projects. We maintain a limited number of supervisory and field personnel to oversee drilling and production operations. Our plans to drill additional wells are determined in large part by the anticipated availability of acceptable drilling equipment and crews. We do not currently have any contractual commitments that ensure we will have adequate drilling equipment or crews to achieve our drilling plans. If our anticipated levels of drilling equipment are not made available to us, we will have to modify our drilling plans, which would cause us to fail to meet our drilling plans and negatively impact our operations. If we cannot meet our drilling plans, the value of your investment in us may decline.

We could lose significant portions of our CBM acreage rights if we do not place into production a sufficient number of CBM wells.

The primary terms of the lease and farm-out agreements pursuant to which we hold our CBM acreage rights will expire between November 2008 and April 2026, after which we will continue to hold our acreage rights only to the extent that we are producing CBM from the covered acreage. Under some of these agreements we will retain only limited acreage rights for each CBM well that we place into production. For us to maintain all of our CBM acreage rights beyond the initial terms of our lease and farm-out agreements, we will be required to significantly expand our drilling operations or renegotiate the terms of these agreements. If we are unable to retain our CBM acreage rights, our growth potential will be negatively impacted, which could cause the value of your investment in us to decline.

We could encounter strong competition for properties in the Illinois Basin.

The natural gas industry is highly competitive. We currently hold substantial CBM acreage rights in the Illinois Basin, but other companies may become active in the area. New entrants could have greater financial and technological resources, which might enable them to outbid us on new acreage or obtain leaseholds, option agreements or farm-out agreements for which we currently have agreements in place when our rights expire or lapse. Any loss of acreage would negatively impact the potential scope of our operations, which would likely have a negative impact on the value of your investment in us.

Because approximately 75% of our CBM acreage rights are inferior to coal mining rights covering the same properties, our affected operations could be displaced by coal mining operations, which would negatively impact our operations.

Under the agreements pursuant to which we hold approximately 75% of our CBM acreage rights, our right to drill for and produce CBM is expressly subject to the mining of coal on the acreage covered by the agreement. We may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining operations will be undertaken. These superior coal rights may restrict the locations where we can drill CBM wells on our projects and may cause some of our CBM operations to be displaced by coal operations. Any such displacement could cover a significant portion of our CBM acreage rights. If we face significant restrictions on where we can drill our CBM wells or a significant number of our CBM wells are displaced by coal mining operations, our operations and financial performance will be negatively impacted.

The CBM rights that we have acquired under lease and option agreements are subject to a number of uncertainties, which, when resolved, could cause us to lose some of our CBM rights.

Under the terms of the lease agreements pursuant to which we have acquired most of our CBM rights, we are entitled to all of the CBM rights held by our lessors in the counties covered by these agreements. However, we face a number of uncertainties regarding what rights our lessors hold.

The issue of who owns CBM gas, as between the coal rights owner and the oil and gas rights owner, is uncertain in Illinois. Although the appellate court in Illinois for the district where most of our acreage rights are situated has ruled that CBM gas is owned by the coal rights owner, the issue has not been addressed by the highest court in Illinois. We believe, based on advice from legal counsel, that under Illinois law ownership will ultimately be found to lie with the coal rights owner. Based on this advice, we generally secure CBM rights from the coal owners. Some of the lessors from which we have acquired CBM rights may hold both the coal rights and the oil and gas rights for the applicable properties, but in some cases it is not certain that these lessors also hold the oil and gas rights. If any litigation in Illinois concludes that CBM rights lie with the oil and gas owner, we could lose some of our CBM rights.

In addition, in some cases the extent of the coal and/or oil and gas rights held by our lessors is uncertain. We conducted no title or deed examinations prior to executing our lease agreements, and our lessors made no warranties as to the acreage or rights covered by the agreements. Although we have now conducted title and deed examinations covering much of the CBM properties under our leases, these examinations are ongoing at all of our projects. There can be no assurance that our rights under our lease agreements include all of the acreage and rights identified in the agreements until title examinations on all of the underlying properties have been completed.

If any of these uncertainties is resolved unfavorably to us, we could lose some of our CBM acreage rights. Any loss of our CBM acreage rights would negatively impact our growth potential, which could cause the value of your investment in us to decline.

We could incur significant costs in connection with disputes over surface rights, which would negatively impact our financial performance.

We have been subject to legal complaints regarding the extent of the surface rights that derive from our CBM rights. On occasion, the owners of properties that are adjacent to our drilling locations have challenged our right to cross their property in accessing our drilling locations and our right to lay gas and water flow lines across their property. The extent of our rights in respect of these issues is uncertain in Illinois. If disputes regarding our surface rights are not resolved in our favor, we may be required to acquire surface rights or access our drilling locations and lay gas and water flow lines in inefficient ways, which would cause us to incur increased operating costs. In addition, we could incur significant costs in legal disputes over our surface rights. If for any reason these operating or legal costs increase significantly, our financial performance will suffer.

We could incur substantial costs to comply with environmental regulations, and our failure to comply with environmental regulations could result in significant fines and/or penalties, either of which could adversely affect our operations.

Our operations are subject to federal, state and local environmental laws and regulations. Although we believe that our operations to date have been conducted in compliance with these regulations, new more restrictive laws or regulations could be adopted, which could force us to expend significant resources to comply with the new requirements. Because CBM exploration is relatively new in the Illinois Basin, the governmental agencies that regulate us, including the Illinois Department of Natural Resources Office of Mines and Minerals, may determine that new laws and regulations are required to govern the growing industry. CBM operations are technologically different from conventional oil and gas operations, and these agencies may determine that existing regulations, which are generally focused on the oil and gas industry, are not sufficient for CBM operations. As CBM activity increases in the Illinois Basin, unexpected regulatory issues may develop, which could impose additional compliance costs on us. Any significant increase in compliance costs could negatively impact our results of operations and could prevent our properties from being commercially viable.

The occurrence of a significant adverse event that is not covered by insurance could have a material adverse effect on our financial condition.

The exploration for and development and production of CBM involves a variety of operating risks, including the possibility of fire, explosion and blow-out from abnormal formation pressure. It is not always possible to fully insure against such risks. An uninsured or underinsured loss could adversely impact our financial condition.

We will incur increased costs as a result of registering in the United States.

In December 2005, we became subject to the reporting requirements of the Securities Exchange Act of 1934. As an SEC registrant, we will incur significant legal, accounting and other expenses that we did not incur as a Canadian public company. We will incur costs associated with complying with the rules and regulations of the SEC, including those adopted under the Sarbanes-Oxley Act of 2002. We currently estimate that these costs will total approximately $1 million on an annual basis. In addition, we continue to be subject to certain securities laws and reporting requirements of the British Columbia Securities Commission and the Alberta Securities Commission. These dual reporting obligations will result in increased compliance costs, which could adversely affect our financial performance.

There is not a substantial amount of trading in our common shares, which could prevent you from selling your common shares at acceptable prices or at all.

Our common shares are currently traded on the American Stock Exchange. There is not a substantial amount of trading in our common shares on the American Stock Exchange. We are not certain that a more active trading market in the stock will develop, or that it will be sustained if it does develop. Because the market for our common shares is limited and is likely to remain limited in the near future, you may not be able to sell your common shares at acceptable prices or at all.

The American Stock Exchange has adopted standards under which it will normally give consideration to removing a security from listing. However, the standards in no way limit the Exchange and it may at any time, in view of the circumstances in each case, remove a security from listing when in its opinion such security is unsuitable for continued trading on the Exchange. These standards include, but are not limited to, consideration of: (i) a company s financial condition and/or operating results; (ii) the company s aggregate market value; (iii) whether a company s common stock sells for a substantial period of time at a low price per share; and (iv) whether a company has complied with its obligations under American Stock Exchange and SEC rules. It is possible that the Exchange could make a determination in the future that our stock is unsuitable for continued trading on the Exchange. If our stock is delisted from the Exchange, it will likely be difficult to effect sales of our stock.

ITEM 1B. ***Unresolved Staff Comments.***

None.

Table of Contents

ITEM 2. *Properties.*

Our corporate headquarters is located in a leased office in Solon, Ohio. Our operations are conducted from an office located in a leased facility in Edwardsville, Illinois. For information about our CBM acreage rights, production and gas reserves, see the section of this report titled CBM Acreage Rights.

ITEM 3. *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 defendants filed a motion to dismiss the second amended complaint, which has been fully briefed and awaits a decision by the Court. We anticipate 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.

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.

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 they were originally entered into. BPI has filed a motion to dismiss the lawsuit under the doctrine of estoppel by deed, arguing that ICG cannot challenge the leases because it acquired the CBM rights subject to those leases, as set forth in the deed from Addington and Meadowlark to ICG, the purchase agreement between those parties, and numerous bankruptcy court filings and orders associated with the approval of the sale. Addington was subsequently acquired by Nytis Exploration Company, LLC, which has intervened in the action and joined in BPI s motion. ICG has opposed BPI s motion, and the Court has held a hearing upon it. BPI has recently learned that, subsequent to filing suit, ICG may have transferred its Perry County coal and CBM rights to Arch Minerals, which is not currently a party to the lawsuit. It is unknown whether Arch will challenge the farm-out agreement. To date, BPI has drilled 10 pilot wells, one pressure observation well, one water disposal well and two test wells on the acreage covered by the farm-out agreement.

We believe that we will be successful in either having the case dismissed or 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 4. *Submission of Matters to a Vote of Security Holders.*

There were no matters submitted to a shareholder vote during the fourth quarter of fiscal 2007.

PART II

ITEM 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities.*

Our common shares are currently traded on the American Stock Exchange under the symbol BPG. The following table sets forth the high and low sales prices per share, in U.S. dollars, as reported by the American Stock Exchange during each of our quarterly periods ending in our 2006 and 2007 fiscal years.

	High	Low
Fiscal Year Ended July 31, 2006		
Quarter ended October 31, 2005	$ 2.25	$ 1.37
Quarter ended January 31, 2006	4.00	1.92
Quarter ended April 30, 2006	3.55	1.20
Quarter ended July 31, 2006	1.60	1.03
Fiscal Year Ended July 31, 2007		
Quarter ended October 31, 2006	$ 1.24	$ 0.48
Quarter ended January 31, 2007	0.70	0.45
Quarter ended April 30, 2007	1.65	0.49

Quarter ended July 31, 2007	1.51	0.58

As of October 22, 2007, we have 73,792,493 common shares outstanding, which are held by approximately 379 shareholders of record. The transfer agent and registrar for our common shares is Computershare Investor Services Inc., a Vancouver, British Columbia company. In addition to our outstanding common shares, as of October 22, 2007, we have reserved 1,579,931 common shares for issuance upon the exercise of outstanding stock options and 5,311,600 common shares for issuance upon the exercise of outstanding warrants.

Table of Contents

Performance Graph

The following graph compares the yearly changes in total shareholder return on our common shares with the total return of the AMEX Composite Index and the S&P Energy Index from July 31, 2002 through July 31, 2007. We assumed an initial investment of $100 on July 31, 2002 and the reinvestment of all dividends. We did not pay any dividends during this five-year period.

Performance Graph

Cumulative Total Return as of July 31, 2007
(assumes a $100 investment at the close of trading on July 31, 2002)

	7/31/02	7/31/03	7/31/04	7/31/05	7/31/06	7/31/07
BPI Energy Holdings, Inc.	100.00	89.58	96.11	260.09	206.16	107.34
AMEX Composite Index	100.00	112.81	148.13	191.64	235.33	271.19
S&P 600 Energy Index	100.00	117.28	190.52	295.32	402.06	431.07

Issuance of Unregistered Securities

In fiscal year 2007, we did not issue any unregistered securities. In fiscal year 2006, we issued the following unregistered securities. Except for the September 26, 2005 issuance, when KeyBanc Capital Markets, a division of McDonald Investments, Inc., and Sanders Morris Harris, Inc. acted as placement agents, we did not use a principal underwriter for any of the issuances listed in the table below. Each such sale was exempt from registration under the Securities Act of 1933, as amended, in reliance on Section 4(2) of the Securities Act and/or regulations issued thereunder as sales to qualified purchasers not involving a public offering.

Date of Sale	Title and Amount of Securities Sold	Offering Price		Aggregate Offering Price	
9/26/05	18,000,000 common shares(1)	USD$	1.69	USD$	30,500,000
8/1/05 through 7/31/06	911,600 common shares(2)	USD$	1.50	USD$	1,367,400
8/1/05 through 7/31/06	975,000 common shares(3)	CAD$	0.80	CAD$	780,000
8/1/05 through 7/31/06	634,375 common shares(4)	CAD$	0.80	CAD$	507,500
8/1/05 through 7/31/06	396,667 common shares(5)	USD$	0.97	USD$	384,767

Table of Contents

(1) These common shares were issued by us in a private placement that closed on September 26, 2005. KeyBanc Capital Markets, a division of McDonald Investments, Inc., and Sanders Morris Harris, Inc. acted as placement agents. The placement agents received commissions totaling $2,538,784 in connection with this sale of securities.

(2) These sales relate to the exercise of warrants issued in conjunction with a private placement of common shares during the period December 30, 2004 to January 13, 2005.

(3) These sales relate to the exercise of warrants issued in conjunction with a private placement of common shares on December 10, 2003.

(4) These sales relate to the exercise of warrants issued in conjunction with a private placement of common shares on September 18, 2003.

(5) These shares were sold pursuant to the exercise of options issued to individuals eligible to participate in our Incentive Stock Option Plan, which has been superseded by our Amended and Restated 2005 Omnibus Stock Plan. The offering price is a weighted average exercise price expressed in U.S. Dollars based on the applicable exchange rate at the time of exercise.

Dividend Policy

We have not paid any cash dividends to date, and currently have no intention of paying any cash dividends on our common shares in the foreseeable future. The declaration and payment of dividends is subject to the discretion of our Board of Directors. The timing, amount and form of dividends, if any, will depend on our results of operations, financial condition and cash requirements.

Equity Compensation Plan Information

The following reflects certain information about our common shares authorized for issuance under compensation plans at July 31, 2007.

Plan Category	Number of Common Shares to be Issued Upon Exercise of Outstanding Options and Warrants	Weighted-Average Exercise Price of Outstanding Options and Warrants	Number of Common Shares Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by shareholders	1,579,931(1)	$ 1.27	4,029,000(2)
Equity compensation plans not approved by shareholders	1,037,200(3)	$ 1.25	N/A

Total	2,617,131	N/A	4,029,000

(1) Represents the number of common shares underlying outstanding options that were issued under our Incentive Stock Option Plan, which has been superseded by our Amended and Restated 2005 Omnibus Stock Plan.

(2) Represents the number of common shares remaining available for issuance under our Amended and Restated 2005 Omnibus Stock Plan. As of July 31, 2007, we have issued 2,921,000 restricted common shares and 50,000 options under our Amended and Restated 2005 Omnibus Stock Plan.

(3) Represents the number of common shares underlying warrants granted to Sanders Morris Harris, Inc. as compensation for serving as placement agent for our December 2004/January 2005 private placement.

Table of Contents

ITEM 6. *Selected Financial Data.*

The following sets forth our selected historical financial data as of July 31, 2007, 2006, 2005, 2004 and 2003 and for our five fiscal years then ended, which has been derived from our financial statements for those years. Our financial statements as of July 31, 2007, 2006 and 2005 and for our fiscal years ended July 31, 2007, 2006 and 2005 and related notes thereto have been audited by Meaden & Moore, Ltd., an independent registered public accounting firm. Our financial statements as of July 31, 2004 and 2003 and for our fiscal years ended July 31, 2004 and 2003 and related notes thereto have been audited by De Visser Gray, an independent registered public accounting firm.

This information should be read together with the section of this report titled Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes included elsewhere in this report.

	For the Year Ended July 31,				
	2007	2006	2005	2004	2003
	(Dollars in thousands, except per share amounts)				
Statement of Operations Data:					
Gas sales(1)	$ 1,204	$ 1,126	$ 118	$	$
Operating expenses	22,397	8,117	6,372	1,081	1,095
Ceiling write-down of gas properties	11,722				
Loss before income taxes	(20,641)	(8,836)	(6,121)	(1,091)	(1,109)
Net loss	(20,641)	(8,836)	(5,397)	(793)	(934)
Net loss per common share	(0.30)	(0.14)	(0.14)	(0.03)	(0.04)
Weighted average number of shares outstanding	69,755,778	62,789,319	37,665,019	25,007,237	21,485,381

	As of July 31,				
	2007	2006	2005	2004	2003
	(Dollars in thousands, except per share amounts)				
Balance Sheet Data:					
Total assets	$ 39,843	$ 49,052	$ 23,528	$ 9,383	$ 6,328
Long-term notes payable (including current maturities)	9,136	216	550	462	378
Cash dividends per common share					

(1) Gas sales commenced in January 2005.

ITEM 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations.*

The following Management s Discussion and Analysis (MD&A) is intended to help you understand our business, financial condition, results of operations, liquidity and capital resources. MD&A is provided as a supplement to, and should be read in conjunction with, the other sections of this report and our consolidated financial statements and related notes. Our MD&A includes the following sections:

Overview and Outlook a general description of our business; drilling plans and capital expenditures; key areas of management focus; measurements; and opportunities, challenges and risks.

Critical Accounting Policies a discussion of accounting policies that require critical judgments and estimates.

Results of Operations an analysis of our consolidated results of operations for the three years presented in our financial statements.

Liquidity and Capital Resources an analysis of our cash flows, sources and uses of cash, contractual obligations and commercial commitments.

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 July 31, 2007, we owned or controlled CBM rights, through mineral leases, a farm-out agreement and ownership of a CBM estate, covering approximately 512,000 total acres in the Basin (approximately 99% of this acreage is undeveloped as of July 31, 2007). Portions of our CBM rights are currently subject to litigation, as described in Item 3 of Part I above. 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 four 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. 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 fiscal year ended July 31, 2007 were $1,204,252 on sales volume of 185,305 Mcf reflecting an increase of 7% in net gas sales and an increase of 37% in sales volume compared to the fiscal year ended July 31, 2006. As previously disclosed, net gas sales in the second quarter of fiscal year 2007 were adversely affected by a nitrogen-related pipeline curtailment that began in October and necessitated six days of downtime followed by a period of constrained sales volume. A nitrogen-rejection unit was installed and began operating in March 2007.

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. In the last quarter of fiscal year 2007 and the first quarter of fiscal year 2008 we have increased our acreage by approximately 12,000 acres, a 2% 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. 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 million. In July 2007, we secured a $75 million advancing term credit facility from GasRock. The initial commitment under this facility was $10.2 million of which we drew $9.1 million at closing.

In April 2006, we hired James E. Craddock, our Chief Operating Officer. Prior to joining us, Mr. Craddock was with Burlington Resources for over 20 years, last serving as Chief Engineer. Mr. Craddock has built a strong in-house technical 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. 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 512,000-acre leasehold position.

During fiscal year 2007, we drilled 45 new wells, including 15 productive wells, seven test wells, two pressure observation wells, two water disposal wells and 19 wells drilled but waiting on completion. Two of these wells are in the Western Illinois Basin Project, 23 are in the Southern Illinois Basin Project, and 20 are in the Northern Illinois Basin Project.

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 (part of the 20 Northern Illinois Basin Project wells listed above). All 12 wells were drilled, completed and started pumping by July 2007.

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.

Management s focus for fiscal year 2008 will be to:

- continue development drilling at the Southern Illinois Basin Project;
- continue 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;
- continue to reduce well drilling and completion costs;
- continue acreage acquisitions;

- 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 512,000 acres of CBM rights and, assuming 80-acre vertical well spacing and the development of all of our acreage, have the possibility of over 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 in 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.

Critical Accounting Policies

Critical Accounting Policies and Estimates

Our 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 a critical component of our results of operations or financial position are discussed below. Our management reviews our critical accounting policies with the Audit Committee of our Board of Directors.

Accounting for CBM Projects

We follow 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 we have 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 capitalized to properties and equipment on the balance sheet. During the fiscal year ended July 31, 2007, we capitalized approximately $532,000 of internal labor and benefit costs determined to be directly attributable to acquisition, exploration or development activities.

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 year end. During the fiscal year ended July 31, 2007, we recognized a ceiling write-down of $11,722,153 as a result of the carrying amount of net gas properties exceeding the full cost ceiling limitation, which was based on a year-end gas price of $6.51 per Mcf.

Capitalized costs of proved gas properties, including estimated future costs to develop the reserves and estimated abandonment costs, net of salvage, are amortized on the units-of-production method using estimates of proved reserves.

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, we determine if an unproved property is impaired if one or more of the following conditions exist:

- there are no firm plans for further drilling on the unproved property;
- negative results were obtained from studies of the unproved property;
- negative results were obtained from studies conducted in the vicinity of the unproved property; or
- the remaining term of the unproved property does not allow sufficient time for further studies or drilling.

Our estimate of proved reserves is based on the quantities of gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows are derived from a report prepared by an independent engineering firm, in accordance with SEC guidelines, based in part on data provided by us. The accuracy of our reserve estimates depends in part on the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

Share-Based Payment

Prior to December 13, 2005, we had 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 our 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. We had 1,579,931 options outstanding under the Incentive Stock Option Plan at July 31, 2007.

On December 18, 2006, our shareholders approved the Amended and Restated 2005 Omnibus Stock Plan (the Omnibus Stock Plan), which our 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 for five years. All of our employees and directors, and any of our consultants or agents 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. No stock options have been issued under the Omnibus Stock Plan. During the current fiscal year, the Committee granted stock awards under the Omnibus Stock Plan in the form of restricted and unrestricted stock to our employees and directors.

In December 2004, the Financial Accounting Standards Board (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 No. 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 Opinion No. 25.

We adopted SFAS No. 123(R), using the modified-prospective method, effective August 1, 2005. Since August 1, 2001, we have followed the fair value provisions of SFAS No. 123 and have 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 granted prior to the adoption of SFAS No. 123(R) vested immediately on the date of grant and, thus, there was no unvested portion of previous stock option grants that vested during fiscal year 2006. Therefore, SFAS 123(R) had no impact on our consolidated financial position or results of operations for fiscal year 2006. We use the Black-Scholes valuation model to estimate the fair value of stock options granted.

Revenue Recognition

All revenue from gas sales is recognized after the gas is produced and delivery takes place. We currently sell all of our gas to one gas marketing company, Atmos Energy Marketing, LLC.

Asset Retirement Obligations

We follow SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 requires us 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 determined on a units-of-production method. Accretion of the asset retirement obligation is recognized over time until the obligation is settled. The future cash outflows associated with settling the asset retirement obligations accrued on the accompanying consolidated balance sheets are excluded from the ceiling test calculation. Our asset retirement obligations relate to the plugging of wells upon exhaustion of gas reserves.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging costs, annual inflation of these costs, the productive life of the wells and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion. Because of the subjectivity of assumptions and the relatively long life of our wells, the costs to ultimately retire these assets may vary significantly from previous estimates.

Deferred Income Taxes

We operate in two tax jurisdictions, the United States and Canada. Primarily as a result of the net losses that we have generated, we have generated deferred tax benefits available for tax purposes to offset net income in future periods. However, a full valuation allowance has been recorded against all deferred tax assets in Canada as we historically have had no income generating operations in Canada. We have recorded a tax benefit in the United States for our fiscal year ended July 31, 2005 to partially offset a previously recorded deferred tax liability.

Table of Contents

Impact of Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the FASB issued FASB Interpretation Number 48, Accounting for Uncertainty in Income Taxes An interpretation of FASB Statement No. 109. 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. Therefore, FASB Interpretation Number 48 will be effective for us beginning in the fiscal year ending July 31, 2008. We are currently assessing the effect of this Interpretation, if any, on our 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, SFAS No. 157 will be effective for us beginning in the fiscal year ending July 31, 2009. We are currently evaluating the statement to determine what impact, if any, it will have on our 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. An entity may elect the fair value option on an instrument-by-instrument basis, with a few exceptions, as long as it applies the fair value option 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, we will need to comply with SFAS No. 159 beginning in the fiscal year ending July 31, 2009, unless we adopt it earlier. We are currently evaluating the statement to determine what impact, if any, it will have on our consolidated financial statements.

Results of Operations

Year Ended July 31, 2007 Compared to Year Ended July 31, 2006

The following table presents our financial data for fiscal year 2007 compared to fiscal year 2006:

	Fiscal Year Ended July 31,		**Dollar**	**%**
	2007	**2006**	**Variance**	**Change**
Revenues:				
Gas sales	$ 1,204,252	$ 1,126,477	$ 77,776	7%
Expenses:				
Lease operating expense	1,607,913	970,791	637,122	66%
General and administrative expense	8,237,838	6,576,131	1,661,708	25%
Depreciation, depletion and amortization	829,154	570,303	258,851	45%
Ceiling write-down of gas properties	11,722,153		11,722,153	100%

Total operating expenses	22,397,058	8,117,224	14,279,834	176%
Operating loss	(21,192,806)	(6,990,748)	(14,202,058)	(203)%
Other income (expense):				
Interest income	564,070	941,351	(377,281)	(40)%
Interest expense	(11,752)	(22,405)	10,653	48%
Other income (expense)		(2,764,443)	2,764,443	100%
Total other income (expense)	552,318	(1,845,497)	2,397,815	130%
Loss before income taxes	(20,640,488)	(8,836,244)	(11,804,244)	(136)%
Deferred income tax benefit				%
Net loss	$ (20,640,488)	$ (8,836,244)	$ (11,804,244)	(136)%

Revenue Revenue from gas sales increased $77,776 in fiscal year 2007, an increase of 7% over fiscal year 2006. Net sales of gas (net of royalties) were 185,305 Mcf for fiscal year 2007 compared to 135,118 Mcf for fiscal year 2006, an increase of 37%. However, our average realized selling price per Mcf decreased to $6.50 in fiscal year 2007 compared to $8.34 in fiscal year 2006. The increase in net sales volume would have been greater except that it was 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 and a portion of the third quarter of fiscal year 2007. A nitrogen-rejection unit was constructed and began operating in March 2007 and daily production and sales have since reached new highs.

Lease operating expense Lease operating expense increased $637,122 in fiscal year 2007, an increase of 66% over fiscal year 2006. Lease operating expenses represent production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental, workovers and labor and other overhead expenses related to producing wells. The increase is primarily due to expenses associated with non-recurring workover projects incurred during the second quarter of fiscal year 2007 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 projects in the Northern Illinois Basin and the hiring of additional personnel.

General and administrative expense General and administrative expense consisted of the following for fiscal year 2007 and 2006:

	Fiscal Year Ended July 31, 2007	2006	Dollar Variance	% Change
Salaries and benefits	$ 3,418,001	$ 2,027,707	$ 1,390,295	69%
Share-based compensation expense	1,645,990	1,377,440	268,550	19%
Professional and regulatory	1,969,631	2,652,384	(682,754)	(26)%
Other	1,204,216	518,600	685,617	132%
Total general and administrative expense	$ 8,237,838	$ 6,576,131	$ 1,661,708	25%

Salaries and benefits increased $1,390,295 in fiscal year 2007, an increase of 69% over fiscal year 2006. The net increase was primarily the result of increased base salaries associated with hiring additional personnel to support our growth, including our Chief Operating Officer during the fourth quarter of fiscal year 2006 and three engineers and a geologist during the first quarter of fiscal year 2007, and cash signing bonuses totaling $350,000 paid to such personnel. In addition, fiscal year 2007 expense includes $250,000 severance paid to our former Chief Financial Officer and General Counsel, who resigned in the first quarter of fiscal year 2007.

Non-cash expense associated with share-based compensation increased $268,550 in fiscal year 2007, a 19% increase over fiscal year 2006. Share-based compensation expense in fiscal year 2007 represents approximately $838,000 of expense recognized on a pro rata basis for the anticipated vesting of restricted shares outstanding, approximately $326,000 of expense related to the grant of 350,000 unrestricted common shares to newly hired members of our technical team and approximately $482,000 of expense related to the grant of 811,161 unrestricted common shares and 50,000 stock options to certain executive officers, employees, non-employee directors and advisory board members primarily in connection with bonuses and directors fees. Share-based compensation expense in fiscal year 2006 represented approximately $527,000 of expense related to the grant of 495,000 stock options to employees and directors, approximately $625,000 of expense related to fully vested shares granted to a new officer and a new director and approximately $225,000 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.

Professional and regulatory fees decreased $682,754 in fiscal year 2007, a decrease of 26% over fiscal year 2006. The net decrease is primarily due to decreased legal fees due to the settlement of the Colt LLC litigation during fiscal year 2006 and lower professional and regulatory fees associated with the filing of our initial SEC registration statements and listing on the American Stock Exchange during fiscal year 2006. These decreases were partially offset by increases in insurance costs, investor relations fees and information technology consulting fees.

Other general and administrative expenses increased $685,617 in fiscal year 2007, an increase of 132% over fiscal year 2006. The increase is primarily due to amortization of costs associated with a separation agreement entered into with our former Chief Financial Officer, newly incurred directors fees, employee relocation costs related to the hiring of our new technical team and additional rent and office expenses related to the Edwardsville, Illinois office, which opened during the fourth quarter of fiscal year 2006.

Depreciation, depletion and amortization expense Depreciation, depletion and amortization expense (DD&A) increased $258,851 in fiscal year 2007, an increase of 45% over fiscal year 2006. We compute DD&A on proved gas properties related to capitalized drilling costs and 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 development costs we incurred on proved gas properties and an increase in our production over fiscal year 2006.

Interest income Interest income decreased $377,281 in fiscal year 2007, a decrease of 40% over fiscal year 2006 due to lower cash balances during fiscal year 2007. We invest our excess cash in overnight sweep accounts and high-grade commercial paper with maturities of 30 days or less.

Ceiling write-down of gas properties We recognized a ceiling write-down of $11,722,153 during the fiscal year ended July 31, 2007 as a result of the carrying amount of net gas properties exceeding the full cost ceiling limitation, which was based on a year-end gas price of $6.51 per Mcf. No ceiling write-down was required during fiscal year 2006.

Other income (expense) Other income (expense) decreased $2,764,443 from fiscal year 2006 due primarily to the loss that was recognized in fiscal year 2006 related to the Colt LLC settlement.

Year Ended July 31, 2006 Compared to Year Ended July 31, 2005

The following table presents our financial data for fiscal year 2006 compared to fiscal year 2005:

	Fiscal Year Ended July 31, 2006	Fiscal Year Ended July 31, 2005	Dollar Variance	% Change
Revenues:				
Gas sales	$ 1,126,477	$ 117,835	$ 1,008,642	864%
Expenses:				
Lease operating expense	971,791	307,178	663,613	216%
General and administrative expense	6,576,131	5,805,121	771,010	13%
Depreciation, depletion and amortization	570,303	260,141	310,162	119%
Total operating expenses	8,117,224	6,372,440	1,744,784	27%
Operating loss	(6,990,748)	(6,254,605)	(736,143)	(12)%
Other income (expense):				
Interest income	941,351	123,219	818,132	664%
Interest expense	(22,405)	(24,820)	2,415	10%
Other income (expense)	(2,764,443)	35,385	(2,799,828)	(7,912)%
Total other income (expense)	(1,845,497)	133,784	(1,979,281)	(1,479)%
Loss before income taxes	(8,836,244)	(6,120,821)	(2,715,423)	(44)%

Deferred income tax benefit		724,470	(724,470)	(100)%
Net loss	$ (8,836,244)	$ (5,397,351)	$ (3,439,893)	(64)%

Revenue Revenue from gas sales increased $1,008,642 in fiscal year 2006, an increase of 864% over fiscal year 2005. We realized our first revenues from the sale of CBM in January 2005. Net sales of gas (net of royalties) were 135,118 Mcf for fiscal year 2006 compared to 17,885 Mcf for fiscal year 2005. Our average realized selling price per Mcf increased to $8.34 in fiscal year 2006 compared to $6.59 in fiscal year 2005.

Lease operating expense Lease operating expense increased $663,613 in fiscal year 2006, an increase of 216% over fiscal year 2005. Lease operating expenses represent production expenses, consisting primarily of repairs and maintenance, fuel and electricity, equipment rental and other overhead expenses related to producing wells. The increase is primarily due to the increase in producing wells and the related increase in gas production.

General and administrative expense General and administrative expense consisted of the following for fiscal years 2006 and 2005:

	Fiscal Year Ended July 31, 2006	**2005**	**Dollar Variance**	**% Change**
Salaries and benefits	$ 2,027,707	$ 894,141	$ 1,133,566	127%
Share-based payments	1,377,440	3,344,738	(1,967,298)	(59)%
Professional and regulatory	2,652,384	1,183,402	1,468,982	124%
Other	518,600	382,840	135,760	35%
Total general and administrative expense	$ 6,576,131	$ 5,805,121	$ 771,010	13%

Salaries and benefits increased $1,133,566 in fiscal year 2006, an increase of 127% over fiscal year 2005. The increase was primarily the result of (i) hiring additional personnel to support our growth throughout fiscal years 2005 and 2006, including a Senior Vice President of Operations (April 2006), a Chief Financial Officer (January 2005) and a Controller (February 2005); (ii) executive bonuses paid during fiscal year 2006; and (iii) general salary increases. We had 16 full-time employees at July 31, 2006 compared to 10 full-time employees at July 31, 2005.

Share-based compensation expense decreased $1,967,298 in fiscal year 2006, a decrease of 59% from fiscal year 2005. During fiscal year 2006, 495,000 stock options were granted, whereas 4,276,056 stock options were granted to various employees and directors in fiscal year 2005. During fiscal year 2006, we issued stock-based awards to employees and directors as follows: (i) 300,000 unrestricted common shares and 300,000 restricted common shares to our newly hired Senior Vice President of Operations; (ii) 140,000 unrestricted common shares to a newly appointed director; and (iii) 495,000 stock options to various employees and directors. We also replaced 2,025,000 stock options with 2,025,000 restricted common shares for key employees and directors during fiscal year 2006. The expense related to the issuance of unrestricted common shares and stock options was fully recognized in fiscal year 2006. A portion of the expense related to the issuance of restricted common shares, representing the vested portion of such shares, was also recognized in fiscal year 2006.

Professional and regulatory fees increased $1,468,982 in fiscal year 2006, an increase of 124% over fiscal year 2005. The increase was primarily the result of increased legal fees incurred in connection with our lawsuit against Colt LLC and higher costs associated with being a public company in the United States. Specifically, the increase resulted from the following:

Additional legal fees incurred in connection with Colt LLC lawsuit	$ 582,528
Increase in executive placement fees	293,325
Increase in printing costs of SEC filings	258,809
Increase in insurance costs	220,936
Increase in AMEX listing fees	115,000
Increase in fees related to accounting, auditing and tax services	68,030

Increase in legal fees incurred in connection with SEC filings		69,920
Decrease in legal fees incurred in connection with surface disputes		(293,305)
Net increase in other professional and regulatory fees		153,739
Total increase over corresponding period in the preceding year	$	1,468,982

Other general and administrative expenses increased $135,760, an increase of 35% over fiscal year 2005, primarily as a result of increased office and travel-related expenses.

Depreciation, depletion and amortization expense DD&A increased $310,162 in fiscal year 2006, an increase of 119% over fiscal year 2005. We compute DD&A on capitalized drilling costs and 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 fiscal year 2005. Additionally, depreciation expense increased due to additions to other support equipment.

Interest income Interest income increased $818,132, an increase of 664% over fiscal year 2005 due to significantly higher average cash balances during fiscal year 2006. The higher cash balances were the result of the net proceeds of $27,883,954 we received in September 2005 related to the private placement of our common shares. We invest our excess cash in overnight sweep accounts and high-grade commercial paper with maturities of 30 days or less.

Other income Other income (expense) decreased $2,799,828, or 7,912%, in fiscal year 2006, primarily due to recognizing $2,951,608 of other expense related to settling our dispute with Colt LLC, partially offset by other income of $127,416 related to the sale of our investment in Hite Coalbed Methane, L.L.C. (HCM) and an increase in distributions from HCM of $44,837 during fiscal year 2006. We believe that these settlement costs will be more than recouped through reduced royalty payments in future years.

Deferred income tax benefit Deferred income tax benefit decreased $724,470 in fiscal year 2006, a decrease of 100% over fiscal year 2005. We recorded a tax benefit in the United States in fiscal year 2005 to partially offset a net recorded deferred tax liability at July 31, 2005. However, no tax benefit was recognized for fiscal year 2006, as we had no net deferred tax liability to offset.

Liquidity and Capital Resources

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 an Advancing Term Credit Agreement (the Credit Agreement) with GasRock Capital LLC (GasRock). The Credit Agreement provides for an initial commitment to us of $10.2 million and the possibility of future advances to us of up to an additional $64.8 million. All future advances under the Credit Agreement beyond the initial commitment will be made in GasRock s discretion. Proceeds are expected to be used for continued development-well drilling at the Southern Illinois Basin Project, drilling of new test wells, pilot projects, lease acquisitions and general and administrative expenses. We may request advances under the Credit Agreement at any time before July 25, 2008, which GasRock may in its discretion extend until July 27, 2010. All amounts then outstanding under the Credit Agreement are due and payable on July 25, 2008, which GasRock may in its discretion extend until July 29, 2011. On July 27, 2007, we received an initial advance of $9,059,566 under the Credit Agreement, which resulted in net proceeds to us of $8,223,912 after the deduction of GasRock s facility fee, investment banking fees, legal fees and other fees and expenses incurred by us in connection with the transaction totaling $835,654.

As of July 31, 2007, we had $9,135,616 in long-term debt and notes payable, of which $9,087,551 is classified as current. Over the past five fiscal years, we raised $43.8 million from the sale of our common shares. Additionally, during that same period, we collected $6.8 million as a result of the exercise of warrants and $2.1 million as a result of the exercise of stock options. Our primary use of these funds has been the acquisition, exploration, testing and development of our CBM properties and rights and payment of lease operating and 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 $1,204,252, $1,126,477 and $117,835 in fiscal years ended July 31, 2007, 2006 and 2005, respectively. We expect revenue from the sale of our CBM to continue to increase due to (i) increased production from existing wells as they proceed through the initial dewatering phase and (ii) additional production generated as a result of drilling additional wells. However, in view of our limited production history, we can provide no assurance that we will achieve a trend of increased production and CBM revenue in the future.

In addition, CBM wells typically must go through a lengthy dewatering phase before making any 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.

We had a cash balance of $11,291,575 at July 31, 2007, compared to $19,279,015 at July 31, 2006. Our revenues and current cash balance will not be sufficient to fund our capital program for fiscal 2008 or our operations beyond July 31, 2008. Therefore, we will need to obtain additional commitments from GasRock under the Credit Agreement and/or raise additional financing in the near future. We currently do not have any specific plans to raise financing in support of our future operations and forecasted capital expenditures, but we anticipate raising the additional required capital through one or a combination of the following:

- additional advances under the Credit Agreement;
- issuance of new debt and/or equity securities; or
- joint ventures.

Cash Used in Operating Activities

Net cash used in operating activities for fiscal year 2007 was $5,491,048 compared with $6,560,034 and $2,474,443 in fiscal years 2006 and 2005, respectively. Net cash used in operating activities increased significantly in fiscal years 2005 and 2006 over previous fiscal years as we added the resources and expertise necessary to support the growth in the size of our projects in the Basin and substantially increased our exploration, development and operating activities. In addition, in order to provide liquidity to our shareholders, we took the steps necessary in fiscal year 2005 to have our stock listed on the American Stock Exchange, which required us to incur a higher level of general and administrative expenses. In fiscal year 2007, our net cash used in operating activities stabilized, decreasing slightly from the prior year.

Net cash 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 and service equipment and personnel;
- lease terms;
- availability of sufficient capital resources; and
- the accuracy of production estimates for current and future wells.

Cash Used in Investing Activities

Net cash used in investing activities for fiscal year 2007 was $10,443,037 compared with $14,517,293 and $6,338,082 in fiscal years 2006 and 2005, respectively. The increase in net cash used in investing activities during fiscal year 2006 over fiscal year 2005 and the decrease in net cash used in investing activities during fiscal year 2007 over fiscal year 2006 are primarily the result of exploration and development costs at our projects.

Cash Provided by Financing Activities

Net cash provided by financing activities for fiscal year 2007 was $7,946,646 compared with $33,104,839 and $15,093,233 during fiscal years 2006 and 2005, respectively. The increases in net cash provided by financing activities during fiscal year 2006 is primarily the result of increased proceeds from common shares issued in private placements and from the exercise of stock options and warrants during fiscal year 2006. During fiscal year 2007, our sole proceeds were from the initial advance of $9,059,566 under the Credit Agreement, which resulted in net proceeds to us of $8,223,912 after the deduction of GasRock s facility fee, investment banking fees, legal fees and other fees and expenses incurred by us in connection with the transaction totaling $835,654. We continue to pay down our long-term notes, making payments of $139,966 in fiscal year 2007, $175,282 in fiscal year 2006 and $41,320 in fiscal year 2005. Our long-term debt and notes payable (including current maturities) increased from $216,015 at July 31, 2006 to $9,135,616 at July 31, 2007. We expect to continue to reduce our long-term notes payable by making scheduled principal payments of approximately $9,087,551 in fiscal year 2008. There are no principal payments scheduled to be made under the Credit Agreement until July 25, 2008, at which time the entire amount, including capitalized interest, is payable unless extended in GasRock s discretion.

Capital Expenditure Plan

We have no contractual commitments for capital expenditures. During the 12-month period ending July 31, 2008, we plan to drill between 30 and 70 new wells. This plan contemplates capital expenditures of approximately $10 million to $23 million. The number of wells that we drill during the 12-month period ending July 31, 2008 will be dependent on (i) data obtained from test wells; (ii) data obtained from our pilot wells; (iii) additional financing we are able to secure, including additional advances we are able to make under the Credit Agreement; and (iv) the risk factors described in this report. In addition to our drilling program, we expect to pursue the acquisition of additional CBM rights during fiscal year 2008. We expect that this capital expenditure program and our other cash requirements will be funded by our cash balance, which as of October 22, 2007 is approximately $5.7 million, and cash raised through additional financing sources that may include additional advances under the Credit Agreement, issuance of new debt and/or equity securities and/or joint ventures. Although we are currently evaluating the best options to raise the necessary funds, we can provide no assurance that we will be able to raise the necessary funds.

Contractual Obligations

	Payments Due by Period				
	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years	Total
Contractual Obligations as of July 31, 2007:					
Long-term debt	$ 9,087,551	$ 48,065	$	$	$ 9,135,616
Equipment leases	164,472	328,944			493,416
Asset retirement obligations				114,172	114,172
Other leases(1)	121,260	109,171	54,598	230,343	515,373,284
Total	$ 9,373,283	$ 486,180	$ 54,598	$ 344,515	$ 10,258,576

(1) These amounts do not include annual minimum royalty payments required to hold mineral lease and farm-out agreements. Although we are not obligated to make these payments under existing mineral leases and farm-out agreements, these payments are required to maintain individual lease/farm-out agreements after the expiration of the initial terms of the lease/farm-out agreements. The lease/farm-out agreements in existence as of October 22, 2007 expire at various times beginning in November 2008. If we were to pay the total minimum royalty payments due under all lease/farm-out agreements in existence as of October 22, 2007, the amount would initially total approximately $100,000 annually and could increase to as much as $220,000 annually.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of July 31, 2007.

ITEM 7A. ***Qualitative and Quantitative Exposure to 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.

Under the terms of our Credit Agreement with GasRock, we are required to enter into derivatives contracts covering approximately 75% of the 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 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 hedging arrangements 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 derivatives to which we are a party as hedges, and accordingly, such contracts are 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 derivatives. It is anticipated, however, that our counterparty, BP, will be able to fully satisfy its obligations under the commodity derivatives contracts. We do not obtain collateral or other security to support our commodity derivatives contracts 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 natural gas revenue on the consolidated statements of operations. Our first commodity derivatives contract was entered into on July 31, 2007 with the first settlement month designated as September 2007. Thus, no settlements occurred during the fiscal year ended July 31, 2007.

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 of July 25, 2008, 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 July 31, 2007 was $9,059,566. A 1% change in interest rates would affect pre-tax net loss by approximately $90,000 per year.

Financial Instruments

Our financial instruments consist of cash and cash equivalents, accounts receivable and debt 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 8. ***Financial Statements and Supplementary Data.***

Our consolidated financial statements are included in this report beginning on page F-1.

ITEM 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

ITEM 9A. *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. Our management, with participation of our Chief Executive Officer and Acting Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rule 13a-15) as of July 31, 2007. Based on that evaluation, our Chief Executive Officer and Acting Chief Financial Officer concluded that our disclosure controls and procedures were effective as of July 31, 2007 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 controls over financial reporting or in other factors that occurred during the fiscal quarter ended July 31, 2007 that materially affected, or are reasonably likely to affect, our internal control over financial reporting.

ITEM 9B. *Other Information.*

None.

PART III

ITEM 10. *Directors, Executive Officers and Corporate Governance.*

We incorporate herein by reference the information appearing under the caption Proposal No. 1 Election of Directors, Section 16(a) Beneficial Ownership Reporting Compliance and Committees of the Board of Directors; Attendance in our definitive proxy statement for our Annual General Meeting of Shareholders, which we will file with the SEC within 120 days after the end of our fiscal year.

Information concerning our executive officers is contained in Item 1 of Part I of this report. We have adopted a Code of Business Conduct and Ethics for employees that applies to our principal executive officer, principal financial officer and controller, as well as all other employees. Our Code of Business Conduct and Ethics can be found on our website at *www.bpi-energy.com.*

ITEM 11. *Executive Compensation.*

We incorporate herein by reference the information appearing under the captions Compensation Discussion and Analysis, Director Compensation and Executive Compensation in our definitive proxy statement.

ITEM 12. *Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters.*

We incorporate herein by reference the information appearing under the caption Beneficial Ownership in our definitive proxy statement.

See Part II, Item 5 for information regarding our equity compensation plans.

ITEM 13. *Certain Relationships and Related Transactions, and Director Independence.*

We incorporate herein by reference the information appearing under the caption Certain Relationships and Related Transactions and Proposal No. 1 Election of Directors in our definitive proxy statement.

ITEM 14. ***Principal Accountant Fees and Services.***

We incorporate herein by reference the information appearing under the caption Proposal No. 2 Ratification of Appointment of Independent Registered Accounting Firm in our definitive proxy statement.

PART IV

ITEM 15. ***Exhibits and Financial Statement Schedules.***

(a) The following documents are filed as part of this report:

(1) Financial Statements

The consolidated financial statements filed as part of this Form 10-K are located as set forth in the index on page F-1 of this report.

(2) Financial Statement Schedules

Not applicable.

(3) Exhibits

The list of exhibits included in the attached Exhibit Index is hereby incorporated herein by reference.

Table of Contents

Appendix A

Glossary of Natural Gas Terms

The following are definitions of selected terms relating to the natural gas industry that are used in this report:

Adsorption. The attachment, through physical or chemical bonding, of gas molecules to the coal surface. The adsorbed gas molecules are trapped within the coal, the stability of which is strongly affected by changes in temperature and pressure.

Casing. Steel pipe set in a well to prevent the hole from sloughing or caving and to enable formations to be isolated. There may be several strings of casing in a well, one inside the other.

Completion. The activities necessary to prepare a well for the production of gas.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Dewatering. A CBM well typically begins dewatering with almost all water production and little or no natural gas production. The continuous production of water from a well that is dewatering reduces the water reservoir pressure on the coals. The reduced reservoir pressure enables the release of the gas within the coal to the wellbore. This results in an increase in the amount of gas production relative to the amount of water production. Dewatering ceases when peak gas production is reached.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production will exceed production expenses and taxes.

Farm-out agreement. An agreement where the owner of a working interest in a gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease.

Fracture. A man-made or hydraulic fracture is formed when a fluid is pumped down a well at high pressures for short periods of time causing a split in the rock formation. As part of this technique, sand or other material may also be injected into the formation to keep the channel open. This technique allows gas to move more freely from the rock pores where they are trapped to a producing well that can bring the gas to the surface.

Horizontal drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation typically yields a well that has the ability to produce higher volumes than a vertical well drilled in the same formation. A horizontal well is designed to replace multiple vertical wells, resulting in lower capital expenditures for draining like acreage and limiting surface disruption.

Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions.

MMBtus. One million British thermal units. One British thermal unit is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

MMcf. One million cubic feet of natural gas at standard atmospheric conditions.

Permeability. The capacity of a geologic formation to allow water or natural gas to pass through it.

Productive well. A well that has been completed and is tied into our gas and/or dewatering system. A productive well may produce only water for a period of time before gas begins to flow through the gas gathering system.

Proved reserves. The estimated quantities of natural gas that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. This definition is consistent with Rule 4-10(a)(2) of Regulation S-X of the SEC s rules and regulations. In reporting proved reserves, we are required to comply with Rule 4-10(a)(2).

Reserves. The quantity of natural gas that is estimated to be commercially recoverable from specific acreage.

Table of Contents

Reservoir. A porous and permeable underground formation, including a coal seam, containing a natural accumulation of producible natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Royalty interest. An interest in a natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage, but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage.

Scf. Standard cubic feet.

Undeveloped acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas, regardless of whether or not such acreage contains proved reserves.

Vertical drilling. A hole drilled vertically into the earth from which gas or water flows or is pumped.

Working interest. An interest in a natural gas lease that gives the owner of the interest the right to drill and produce natural gas on the leased acreage and requires the owner to pay its proportionate share of the costs of drilling and production operations.

BPI ENERGY HOLDINGS, INC.

Index to Consolidated Financial Statements

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders of
BPI Energy Holdings, Inc.
Solon, Ohio

We have audited the accompanying consolidated balance sheets of BPI Energy Holdings, Inc. and its subsidiary as of July 31, 2007 and 2006, and the related statements of operations, shareholders equity, and cash flows for the three years ended July 31, 2007. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of BPI Energy Holdings, Inc. and its subsidiary as of July 31, 2007 and 2006, and the results of its operations and its cash flows for the three years ended July 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ MEADEN & MOORE, LTD.
Certified Public Accountants

October 24, 2007
Cleveland, Ohio

BPI ENERGY HOLDINGS, INC.

Consolidated Balance Sheets

	July 31 2007	July 31 2006
	(Dollars in thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 11,292	$ 19,279
Accounts receivable	94	106
Other current assets	1,948	165
Total current assets	13,334	19,550
Property and equipment, at cost:		
Gas properties, full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of $899 and $375 and ceiling write-down of $11,722 and $0	16,631	25,065
Unproved, excluded from amortization	8,533	3,368
Support equipment, net of accumulated depreciation and amortization of $741 and $548	552	499
Net gas properties	25,716	28,932
Other property and equipment, net of accumulated depreciation and amortization of $152 and $39	473	309
Net property and equipment	26,189	29,241
Restricted cash	100	100
Other non-current assets	220	161
Total assets	$ 39,843	$ 49,052
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 1,371	$ 1,493
Current maturities of long-term debt and notes payable	9,088	141
Accrued liabilities and other	1,503	649
Total current liabilities	11,962	2,283
Long-term debt and notes payable, less current maturities	48	75
Asset retirement obligation	114	71
Total liabilities	12,124	2,429
Shareholders Equity		
Common shares, no par value, authorized 200,000,000 shares, 72,524,493 and 70,812,540 issued and outstanding	67,946	67,946
Additional paid-in capital	7,608	5,871

Accumulated deficit	(47,835)	(27,194)
Total shareholders equity	27,719	46,623
Total liabilities and shareholders equity	$ 39,843	$ 49,052

See notes to consolidated financial statements

F-3

Table of Contents

BPI ENERGY HOLDINGS, INC.

Consolidated Statements of Operations

	Years Ended July 31		
	2007	2006	2005
	(Dollars in thousands, except per share data)		
Revenue			
Gas sales	$ 1,204	$ 1,126	$ 118
Operating expenses			
Lease operating expense	1,608	971	307
General and administrative expenses	8,238	6,576	5,805
Depreciation, depletion and amortization	829	570	260
Ceiling write-down of gas properties	11,722		
Total operating expenses	22,397	8,117	6,372
Operating loss	(21,193)	(6,991)	(6,254)
Other income (expense):			
Interest income	564	941	123
Interest expense	(12)	(22)	(25)
Other income (expense)		(2,764)	35
	552	(1,845)	133
Loss before income taxes	(20,641)	(8,836)	(6,121)
Deferred income tax benefit			724
Net loss	$ (20,641)	$ (8,836)	$ (5,397)
Basic and diluted net loss per share	$ (0.30)	$ (0.14)	$ (0.14)
Weighted average common shares outstanding	69,755,778	62,789,319	37,665,019

See notes to consolidated financial statements

Table of Contents

BPI ENERGY HOLDINGS, INC.

Consolidated Statements of Shareholders Equity

	Common Shares		Additional		Total
	Shares	Amount	Paid-in Capital	Accumulated Deficit	Shareholders Equity
			(Dollars in thousands)		
Balance, July 31, 2004	28,374,296	$ 19,508	$ 1,163	$ (12,961)	$ 7,710
Proceeds from stock options exercised	2,254,333	1,617			1,617
Proceeds from warrants exercised	2,861,342	1,443			1,443
Net proceeds from shares issued in private placement December 29, 2004(1)	2,400,000	2,794			2,794
Net proceeds from shares issued in private placement December 30, 2004(2)	4,032,000	4,694			4,694
Net proceeds from shares issued in private placement January 6, 2005(3)	3,723,200	4,334			4,334
Net proceeds from shares issued in private placement January 12, 2005(4)	216,800	252			252
Bonus shares	50,990	23			23
Share-based compensation stock options			3,345		3,345
Other			(14)		(14)
Net loss				(5,397)	(5,397)
Balance, July 31, 2005	43,912,961	34,665	4,494	(18,358)	20,801
Proceeds from stock options exercised	396,667	383			383
Proceeds from warrants exercised	5,822,075	5,014			5,014
Net proceeds from shares issued in private placement September 23, 2005(5)	18,000,000	27,884			27,884
Share-based compensation stock options			527		527
Share-based compensation common shares (number of shares include non-vested portion of restricted stock)	2,680,837		850		850
Net loss				(8,836)	(8,836)
Balance, July 31, 2006	70,812,540	67,946	5,871	(27,194)	46,623
Share-based compensation stock options			31		31
Share-based compensation common shares (number of shares include	1,795,883		1,843		1,843

non-vested portion of restricted stock)					
Surrender of shares to pay taxes	(83,930)		(137)		(137)
Net loss				(20,641)	(20,641)
Balance, July 31, 2007	72,524,493	$ 67,946	$ 7,608	$ (47,835)	$ 27,719

(1) net of share issuance costs of $206

(2) net of share issuance costs of $346

(3) net of share issuance costs of $320

(4) net of share issuance costs of $19

(5) net of share issuance costs of $2,620

See notes to consolidated financial statements

F-5

Table of Contents

BPI ENERGY HOLDINGS, INC.

Consolidated Statements of Cash Flows

	Years Ended July 31		
	2007	2006	2005
	(Dollars in thousands)		
Cash Provided by (Used in):			
Operating Activities			
Net loss	$ (20,641)	$ (8,836)	$ (5,396)
Adjustments to reconcile net loss to net cash used in operating activities:			
Depreciation, depletion, amortization and ceiling write-down	12,551	570	260
Share-based compensation expense	1,646	1,377	3,345
Gain on sale of marketable securities		(127)	(42)
Loss on disposal of property and equipment			16
Deferred income tax benefit			(725)
Accretion of asset retirement obligation	4	3	
Other		7	21
Changes in assets and liabilities:			
Accounts receivable	12	(71)	(35)
Other current assets	(119)	(141)	21
Accounts payable	262	8	81
Accrued liabilities and other	854	649	11
Other assets and liabilities	(59)		(32)
Net cash used in operating activities	(5,490)	(6,561)	(2,475)
Investing Activities			
Proceeds from sale of marketable securities		551	114
Business acquisition, net of cash acquired			(858)
Additions to property and equipment	(10,444)	(15,068)	(5,416)
Acquisition of equity interest in joint venture			(78)
Increase in restricted cash			(100)
Net cash used in investing activities	(10,444)	(14,517)	(6,338)
Financing Activities:			
Proceeds from issuance of debt	9,060		
Payments on long-term debt and notes payable	(140)	(175)	(41)
Payment of deferred financing costs	(836)		
Payments for surrender of shares	(137)		
Net proceeds from issuance of common shares		33,280	15,135
Net cash provided by financing activities	7,947	33,105	15,094
Net increase (decrease) in cash and cash equivalents	(7,987)	12,027	6,281
Cash and cash equivalents at the beginning of the year	19,279	7,252	971
Cash and cash equivalents at the end of the year	$ 11,292	$ 19,279	$ 7,252

Supplementary disclosure of cash flow information:			
Cash payments			
Interest paid	$ 12	$ 19	$ 12
Non-cash transactions:			
Vesting of shares in connection with separation agreement	228		
Acquisition of equipment by issuance of notes payable		234	118
Cancellation of convertible note payable		392	
Cashless exercise of warrants		284	
Non-cash financing fees	600		

See notes to consolidated financial statements

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements
July 31, 2007, 2006 and 2005
(Dollars in thousands)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Going Concern

These consolidated financial statements include the accounts of BPI Energy Holdings, Inc. and its wholly owned U.S. subsidiary, BPI Energy, Inc. (collectively, the Company). The Company has presented these financial statements in accordance with U.S. generally accepted accounting principles. 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.

These 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 years, including $20,641 in the current year, and has an accumulated deficit of $47,835 at July 31, 2007. In addition, the current year net loss includes a full cost ceiling write-down of the Company s gas properties in the amount of $11,722. In order to continue as a going concern, the Company must be able to finance both its current operations and future exploration and development costs, and be able to resolve any environmental, regulatory or other constraints, which may hinder the successful development of its properties.

The Company has historically financed its activities primarily from the proceeds of private placements of its common shares and most recently from an advance on its $75 million advancing term credit facility that closed on July 27, 2007, as discussed in Note 9. The Company plans to finance future operations through sources that may include additional advances under its credit agreement, issuance of new debt and/or equity securities and/or joint ventures. Although the Company is currently evaluating its options to raise the necessary funds, it can provide no assurance that it will be successful in doing so.

Use of Estimates

The preparation of these 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.

Revenue Recognition and Customer Concentration

All revenue from gas sales is recognized after the gas is produced and delivery takes place. The Company currently sells all of its gas to one gas marketing company, Atmos Energy Marketing, LLC. Although the Company sells all of its production to a single purchaser, there are numerous other purchasers in the Illinois Basin to whom the Company believes it could sell its production; therefore, the loss of its single purchaser would likely not have an adverse effect on the Company s operations.

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

Investments in Unconsolidated Entities

The equity method of accounting is used to account for investments in and earnings or losses of affiliates that the Company does not control, but over which it exerts significant influence. The cost method of accounting is used for all other non-controlled investments. The Company used the cost method to account for its indirect interest in the Jericho Project through its 49% interest in Hite Coalbed Methane, L.L.C. (HCM), as the Company did not exert significant influence over HCM. As described in Note 6, the Company sold its investment in HCM during the fiscal year ended July 31, 2006 and recognized a gain on the sale in the amount of $127, which is included in other income (expense) in the fiscal year ended July 31, 2006 consolidated statement of operations. The Company considers whether the fair values of any of its investments have declined below their carrying value whenever adverse events or changes in circumstances indicate that recorded values may not be recoverable. If the Company considered any such decline to be other than temporary, a write-down would be recorded to estimated fair value.

Cash and Cash Equivalents

Cash and cash equivalents consist of highly liquid investments with a maturity date of three months or less when purchased and are carried at cost, which approximates fair value.

Accounts Receivable

Accounts receivable represents 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 July 31, 2007 and 2006, 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.

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 Capital LLC (GasRock), the Company is required to enter into derivatives 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 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 has entered into a costless collar contract with BP Corporation North America Inc. (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 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 forward price for each month. The Company expects that it will enter into additional hedging arrangements during

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

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 the commodity derivatives to which they are a party as hedges, and accordingly, such contracts are 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. 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 derivatives. It is anticipated, however, that its counterparty, BP, will be able to fully satisfy its obligations under the commodity derivatives contracts. The Company does not obtain collateral or other security to support its commodity derivatives contracts 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. The Company s first commodity derivatives contract was entered into on July 31, 2007 with the first settlement month designated as September 2007. Thus, no settlements occurred during the fiscal year ended July 31, 2007.

Fair Value of Financial Instruments

The carrying amount reported on the balance sheet for cash, accounts receivable, accounts payable and accrued liabilities approximates fair value because of the immediate or short-term maturity of these financial instruments.

The carrying amount of debt and other long-term notes payable approximates fair value based on current rates available to the Company for instruments of the same remaining terms and maturities.

Restricted Cash

The Company negotiated an agreement with one of its surface rights owners to ensure the Company s access to its wells and gas gathering systems. As part of the agreement, the Company deposited $100 in a trust account to serve as a performance bond to ensure the Company performs its obligations under the terms of the agreement. The Company has recorded this amount as a non-current asset at July 31, 2007 and 2006.

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. During the fiscal year ended July 31, 2007, the Company capitalized $532 of internal labor and benefit costs determined to be directly attributable to acquisition, exploration or development activities.

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 year end. During the fiscal year ended July 31, 2007, the Company recognized a ceiling write-down of $11,722 as a result of the carrying amount of net gas properties exceeding the full cost ceiling limitation, which was based on a year-end gas price of $6.51 per Mcf.

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

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.

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

Other Property and Equipment

Other property and equipment is stated at cost 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.

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.

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

The following table summarizes the activity for the Company s asset retirement obligations for the fiscal years ended July 31, 2007 and 2006, respectively:

	Fiscal Year Ended July 31	
	2007	**2006**
Beginning asset retirement obligation	$ 71	$ 35
Additional liability incurred	23	25
Accretion expense	4	3
Change in estimate	35	8
Asset retirement costs incurred	(38)	
Loss on settlement of liability	19	
	$ 114	$ 71

During the fiscal year ended July 31, 2007, the Company incurred $38 related to plugging wells, primarily related to 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 $19. The Company changed its estimate of future costs associated with plugging wells, resulting in an increase to the asset retirement obligation of $35, which was recorded during the fiscal year ended July 31, 2007.

Accounting for Long-Lived Assets

The Company follows SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets . Under SFAS No. 144, all long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable. The carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value.

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.

Share-Based Compensation

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. The Company had 1,579,931 options outstanding under the Incentive Stock Option Plan at July 31, 2007.

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

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. During the current fiscal year, the Committee granted stock awards under the Omnibus Stock Plan in the form of stock options and restricted and unrestricted stock to employees, directors, and advisory board members of the Company. The transactions involving the granting of these stock awards are described more fully in Note 14.

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 July 31, 2007, the Company has issued 50,000 stock options, 2,532,338 restricted common shares, and 388,662 unrestricted common shares under the Omnibus Stock Plan and has 4,029,000 common shares available for future issuance under the Plan.

In December 2004, the FASB issued 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 Opinion 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 unvested portion of previous stock option grants that vested during the fiscal year ended July 31, 2006 or in fiscal years 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 valuation model to estimate the fair value of stock options granted. The vesting of stock awards is recognized as share-based compensation expense using the straight-line method.

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-

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

dilutive. The following items were excluded from the computation of diluted loss per share at July 31, 2007, 2006, and 2005, respectively, as the effect of their assumed exercises would be anti-dilutive:

	July 31		
	2007	**2006**	**2005**
Outstanding warrants	5,311,600	5,311,600	11,168,675
Outstanding stock options	1,579,931	1,823,265	4,227,279
Nonvested portion of restricted shares issued	2,437,338	2,325,000	
	9,328,869	9,459,865	15,395,954

Reclassifications

Certain items included in prior years consolidated financial statements have been reclassified to conform to current year presentation.

Impact of Recently Issued Accounting Standards Not Yet Adopted

In June 2006, the FASB issued FASB Interpretation Number 48, Accounting for Uncertainty in Income Taxes An interpretation of FASB Statement No. 109. 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. Therefore, the Company will need to comply with FASB Interpretation Number 48 beginning in the fiscal year ending July 31, 2008. The Company is currently assessing the effect of this Interpretation, if any, 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 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. MARKETABLE SECURITIES

The Company sold its remaining 432,000 shares of Pyng Technologies Corp. (Pyng), a TSX Venture listed public company, during the fiscal year ended July 31, 2005 and recognized a gain on the sale in the amount of $42.

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

The gain is included within other income (expense) in the fiscal year ended July 31, 2005 consolidated statement of operations. The Company considered these shares of Pyng to be trading securities and recorded unrealized holding gains and losses directly to earnings.

3. OTHER CURRENT ASSETS

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

	July 31	
	2007	2006
Deferred financing costs	$ 1,436	$
Separation Agreement	322	
Prepaid expenses and other	190	165
	$ 1,948	$ 165

4. ACCRUED LIABILITIES

Accrued liabilities consist of the following at July 31, 2007 and 2006, respectively:

	At July 31	
	2007	2006
Employee compensation	$ 1,112	$ 468
Professional fees	133	112
Separation agreement	100	31
Directors fees	57	31
Other	101	38
	$ 1,503	$ 649

The separation agreement represents amounts due 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 8 for further explanation of this agreement.

5. PURCHASE OF ILLINOIS MINE GAS, L.L.C.

On March 3, 2005, the Company purchased the remaining interest in Illinois Mine Gas, L.L.C. (IMG), a 50% joint venture with Vessels Coal Gas, Inc. IMG was created to explore and develop abandoned mine works in the Illinois Basin for the production and sale of methane gas. The Company previously accounted for its 50% investment in IMG under the equity method of accounting. The aggregate purchase price of $900 in cash, less cash received in the amount of $42, was assigned entirely to IMG s coal mine methane properties.

6. SALE OF INVESTMENT IN HITE COALBED METHANE, L.L.C.

On January 4, 2006, the Company sold its 49% interest in Hite Coalbed Methane, L.L.C. (HCM) for $551 in cash and cancellation of the Company s convertible note payable in the amount of $392, plus accrued interest of $31. The note was convertible into 390,537 of the Company s common shares. The Company accounted for its investment in HCM under the cost method of accounting. The total consideration received of $974 resulted in a gain on the sale of the investment of $127, which is included in other income (expense) in the Company s statement of operations for the fiscal year ended July 31, 2006. The Company also received its final distribution of net income from HCM during the fiscal year ended July 31, 2006 in the amount of $52, which is included as part of other income (expense) in the statement of operations for the fiscal year ended July 31, 2006.

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

7. OTHER NON-CURRENT ASSETS

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

	July 31	
	2007	2006
Separation Agreement	$ 59	$
Advance royalties	161	161
	$ 220	$ 161

8. 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 and medical and dental insurance coverage for two years from the date of the agreement. The cash payment of $250 was expensed during the current fiscal year and the cost of medical and dental coverage, which is not material, is being expensed as incurred.

Consulting grant of 40,000 unrestricted common shares and cash payments totaling $50 in periodic installments from October 15, 2006 through December 31, 2006 in 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. In lieu of issuing the 40,000 shares to the former officer and director, the Company deemed them to have been contemporaneously surrendered in partial satisfaction of tax withholding obligations paid in cash by the Company.

Non-compete/Non-solicitation cash payments of $100 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 agreement not to compete with the Company or to solicit any of its employees for a period of two years. Of the 475,000 restricted shares immediately vested, 84,163 had vested during the fiscal year ended July 31, 2006 and were surrendered by the former officer and director to pay for the exercise of warrants obtained in an April 2004 private placement of the Company s common shares.

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 July 31, 2007, $381 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 $322 shown as current and representing the amount to be amortized over the next year. As of July 31, 2007, $100 is recorded as a current liability reflecting the final payment due under the non-compete/non-solicitation agreement on

January 2, 2008. The Company expensed $236 and $50 in connection with the consulting services and the non-compete/non-solicitation agreement, respectively, during the fiscal year ended July 31, 2007.

9. LONG-TERM DEBT AND NOTES PAYABLE

GasRock Credit Facility

On July 27, 2007, the Company entered into an Advancing Term Credit Agreement (the 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. The Company may request advances under the Credit Agreement at any time before July 25, 2008, which GasRock may in its discretion extend

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

until July 27, 2010. All amounts then outstanding under the Credit Agreement are due and payable on July 25, 2008 (the Loan Termination Date), which GasRock may in its discretion extend until July 29, 2011.

On July 27, 2007, the Company received an initial advance of $9,060 under the Credit Agreement, which resulted in net proceeds to the Company of $8,224 after the deduction of GasRock s facility fee, investment banking fees, legal fees and other fees and expenses incurred by the Company in connection with the transaction totaling $836. The Company has capitalized such fees and expenses incurred in connection with this transaction as deferred financing fees and is amortizing them over the initial term of the Credit Agreement using the interest method. The initial advance is expected to be used for continued drilling of development wells at the Southern Illinois Basin Project, drilling of new test wells, pilot projects, possible lease acquisitions and general and administrative expenses.

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 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 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 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 two percent 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 added to 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 one percent royalty in all CBM produced and saved from the Company s existing leased and owned CBM properties and an additional four percent 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 one percent royalty interest to GasRock on new mineral interests acquired by the Company after July 25, 2008 and the same four percent royalty interest on new wells drilled by the Company that are funded by draws under the Credit Agreement. The Company estimates that the fair value of the royalty interests granted to GasRock is approximately $600 and has recorded this amount as an increase to deferred financing costs included in other current assets and a decrease to the full cost pool included as part of gas properties-proved on the consolidated balance sheet as of July 31, 2007.

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.

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

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 four percent per annum.

Long-Term Notes Payable

The Company has outstanding term notes payable related to vehicles and equipment as follows:

	July 31	
	2007	**2006**
Case Credit term note due in fiscal year 2007, 6.50%	$	$ 15
GMAC term note due in fiscal year 2009, 6.50%	14	21
GMAC term notes due in fiscal year 2010, 6.1% to 6.50%	62	81
Caterpillar Financial Services term note due in fiscal year 2007, 7.0%		99
	76	216
Less current maturities	(28)	(141)
Long-term notes payable	$ 48	$ 75

The notes are collateralized by the related vehicles and equipment.

The annual principal maturities of loans under the GasRock credit facility and the long-term notes payable for the five fiscal years subsequent to July 31, 2007 are as follows:

2008	$ 9,088
2009	30
2010	18
	$ 9,136

10. INCOME TAXES

The income tax benefit consists of the following:

	Year Ended July 31		
	2007	2006	2005
Current	$	$	$
Deferred:			
Canadian			
United States			(581)
U.S. state taxes			(143)
Total deferred income taxes			(724)
Total income tax benefit	$	$	$ (724)

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

A reconciliation of income tax computed at the statutory Canadian tax rate and the Company s effective rate is as follows:

	Year Ended July 31		
	2007	**2006**	**2005**
Statutory Canadian income tax rate	(36.00)%	(36.00)%	(36.00)%
Stock-based compensation	%	(4.71)%	19.66%
Non-deductible stock issuance costs	%	2.10%	1.43%
Current year Canadian loss with no tax benefit	0.08%	(4.61)%	2.32%
Gain on intercompany asset transfers	5.12%	%	%
Net change in deductible temporary differences due to foreign currency conversion and expired losses	(2.43)%	3.16%	(5.38)%
Increase in valuation allowance	36.23%	43.44%	7.32%
Other	(3.00)%	(3.38)%	(1.19)%
Effective income tax rate	%	%	(11.84)%

The components of the net deferred tax liability at July 31, 2007 and 2006 are shown below:

	July 31, 2007		
	United States	**Canada**	**Total**
Deferred tax assets:			
Net operating loss carryforwards	$ 18,808	$ 570	$ 19,378
Stock-based compensation	629		629
Resource related allowances		878	878
Total non-current deferred tax asset	19,437	1,448	20,885
Valuation allowance	(12,771)	(1,448)	(14,219)
Net deferred tax assets	6,666		6,666
Deferred tax liabilities:			
Net property plant and equipment			
Total non-current deferred tax liability	(6,666)		(6,666)
Net deferred tax liability	$	$	$

	July 31, 2006		
	United States	Canada	Total
Deferred tax assets:			
Net operating loss carryforwards	$ 11,364	$ 513	$ 11,877
Resource related allowances	769		769
Investments and advances to subsidiaries		1,762	1,762
Total non-current deferred tax asset	12,133	2,275	14,408
Valuation allowance	(4,466)	(2,275)	(6,741)
Net deferred tax assets	7,667		7,667
Deferred tax liabilities:			
Net property plant and equipment	(7,667)		(7,667)
Total non-current deferred tax liability	(7,667)		(7,667)
Net deferred tax liability	$	$	$

F-18

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

The Company considers the need to record a valuation allowance against deferred tax assets on a country-by-country basis, taking into account the effects of local tax law. A valuation allowance is not recorded when it is determined that sufficient positive evidence exists to demonstrate that it is more likely than not that a deferred tax asset will be realized. The main factors considered are: (i) the nature, amount and expected timing of reversal of taxable temporary differences, and (ii) opportunities to implement tax plans that affect whether tax assets can be realized. A valuation allowance has been recorded against the net deferred tax assets as of July 31, 2007 and 2006 because the Company believes it is more likely than not it will be unable to realize the benefit of these assets.

An increase in the U.S. valuation allowance of $8,305 has been recorded during the current fiscal year to reduce the amount of the U.S. deferred tax assets to an amount equal to the recorded U.S. deferred tax liabilities. A decrease in the Canadian valuation allowance of $827 has been recorded during the current fiscal year to reflect a gain recognized on the transfer of assets and the expiration of net operating losses in Canada. Historically, the Company has had no income generating operations in Canada and any future income is too uncertain to justify not recording a valuation allowance.

The Company s net operating loss carryforwards at July 31, 2007 expire as follows:

	Year Ended July 31			
	2011	2012	2013 and Later	Total
Canadian	$ 322	$ 315	$ 992	$ 1,629
United States			48,224	48,224
	$ 322	$ 315	$ 49,216	$ 49,853

At July 31, 2007 the Company also has $2,439 of Canadian resource related deductions that have no expiration date. The Company s ability to utilize previously incurred net operating losses to offset future taxable income, if any, could be limited due to a recent ownership change within the meaning of Section 382 of the Internal Revenue Code of 1986.

11. SHAREHOLDERS EQUITY

Common shares The Company has authorized 200,000,000 shares without par value, of which 72,524,493 and 70,812,540 were issued and outstanding as of July 31, 2007 and 2006, respectively. Shares issued and outstanding at July 31, 2007 and 2006 include 2,437,338 and 2,325,000 restricted shares, respectively, expected to vest in future periods.

Additional paid-in capital Amounts recorded of $7,608 and $5,871 at July 31, 2007 and 2006, respectively, represent the cumulative amounts of share-based compensation as of each fiscal year-end.

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.

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

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

Number Outstanding	Exercise Price	Expiry Date
4,274,400	$1.50	December 13, 2007
643,200	$1.25	December 31, 2009
394,000	$1.25	January 12, 2010
5,311,600		

12. COMMITMENTS AND CONTINGENCIES

The Company has operating lease commitments expiring at various dates. Such leases generally contain renewal options. At July 31, 2007, future minimum lease payments under non-cancellable operating leases are as follows:

2008	$ 286
2009	255
2010	183
2011	19
2012	19
Thereafter	247
	$ 1,009

The leases are principally for office space and gas collection equipment. Rental payments for all operating leases amounted to approximately $253 during the fiscal year ended July 31, 2007.

Certain of the Company s mineral leases and farm-out agreements are subject to annual minimum royalty payments required to hold the mineral leases and farm-out agreements. Although the Company is not obligated to make these payments under existing mineral leases and farm-out agreements, these payments are required to maintain individual leases/farm-out agreements after the expiration of the initial terms of the lease/farm-out agreements. The mineral leases/farm-out agreements in existence as of July 31, 2007 expire at various dates beginning in November 2008. If the Company were to pay the total minimum royalty payments due under all mineral leases/farm-out agreements in existence as of July 31, 2007, the amount would initially total approximately $100 annually and could increase to as much as $220 annually.

13. 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

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

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.

14. SHARE-BASED COMPENSATION

Stock Options

The table below summarizes stock options activity for the three years ended July 31, 2007. All stock options through the fiscal year ended July 31, 2006 were granted under the Incentive Stock Option Plan with exercise prices denominated in Canadian Dollars. U.S. Dollar amounts shown in the tables below through the fiscal year ended July 31, 2006 were derived using published exchange rates on the date of the transaction for grants, expirations, exercises and surrenders and at year-end exchange rates for options outstanding as of each fiscal year-end. Stock options granted during the fiscal year ended July 31, 2007 were granted under the Omnibus Stock Plan with exercise prices denominated in U.S. Dollars. All stock options granted were fully vested on the date of grant.

	Number of Options	Weighted Average Exercise Price
Outstanding at July 31, 2004	2,230,556	$ 0.59
Granted exercise price equals market price of stock on date of grant	3,423,278	1.64
Granted exercise price less than market price of stock on date of grant	852,778	0.96
Expired	(25,000)	0.98
Exercised	(2,254,333)	0.72
Outstanding at July 31, 2005	4,227,279	1.49
Granted exercise price equals market price of stock on date of grant	495,000	1.79
Expired	(320,000)	1.79
Exercised	(554,014)	1.24
Exchanged for restricted stock	(2,025,000)	1.82
Outstanding at July 31, 2006	1,823,265	1.17
Granted exercise price equals market price of stock on date of grant	50,000	0.83
Expired	(293,334)	0.60
Outstanding at July 31, 2007	1,579,931	$ 1.27

Included in stock options exercised during fiscal year 2006 are 107,800 stock options surrendered by an officer/director of the Company in order to exercise 173,250 warrants for the Company s common shares in lieu of transferring cash. The fair value of the stock options surrendered in this transaction equaled the total exercise price of the warrants using the Black-Scholes valuation model to value the stock options on the date of the transaction. The assumptions used in the Black-Scholes valuation model were as follows:

Risk-free interest rate	4.75%
Expected dividend yield	Nil
Expected stock price volatility	95%
Expected option life	3.6 years

The risk-free interest rate used was based on the U.S. Treasury yield curve at the time of the transaction. The expected stock price volatility was based solely on the historical volatility of the Company s common shares during

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

the historical period equivalent to the expected option life. In estimating expected volatility, the Company used a combination of the historical volatility of its common shares for the period that they began trading on the American Stock Exchange and the historical volatility of its common shares on the TSX Venture Exchange for the necessary period in order to reflect the expected remaining life of the stock options. The expected option life represents the remaining contractual life of the stock options surrendered.

The Company recorded share-based compensation expense for stock options granted to employees and directors in the amount of $31, $527 and $3,345 in fiscal years ended July 31, 2007, 2006 and 2005, respectively. The fair value of stock options granted was estimated using the Black-Scholes valuation model with the following assumptions:

	Year Ended July 31,		
	2007	2006	2005
Risk-free interest rate	5.0%	3.3%	3.0 3.7%
Expected dividend yield	Nil	Nil	Nil
Expected stock price volatility	97%	95%	69-81%
Expected option life	5 years	3 years	3 years

The risk-free interest rate for periods within the contractual life of the options was based on the U.S. Treasury yield curve in effect at the time of grant for options granted during fiscal years ended July 31, 2007 and 2006 and based on the equivalent Canadian rate in prior fiscal years. The expected stock price volatility is based solely on the historical volatility of the Company s common shares during the historical period equivalent to the expected option life. In estimating expected volatility, the Company used the historical volatility of its stock on the TSX Venture Exchange or a combination of the historical volatility of its stock for the period that it began trading on the American Stock Exchange and the historical volatility of its stock on the TSX Venture Exchange for the necessary period in order to reflect the expected remaining life of the stock options. The expected option life represents the Company s best estimate of the time that options granted are expected to be outstanding based on prior experience.

The weighted average fair value per option at the date of the grant for options granted in fiscal years ended July 31, 2007, 2006 and 2005 was as follows:

	2007	2006	2005
Exercise price equals market price of stock on date of grant	$ 0.63	$ 1.07	$ 0.81
Exercise price is less than market price of stock on date of grant			0.66
Total grants	$ 0.63	$ 1.07	$ 0.78

Option pricing models require the input of highly subjective assumptions, particularly as to the expected price volatility of the stock. Changes in these assumptions can materially affect the fair value estimate, and therefore it is management s view that the existing models do not necessarily provide a single reliable measure of the fair value of the Company s stock option grants.

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

The following table summarizes information about options outstanding as of July 31, 2007:

Exercise Price	Number Outstanding	Remaining Life (Years)	Expiry Date
$0.49	345,000	1.3	November 3, 2008
0.70	10,000	2.1	September 22, 2009
0.83	50,000	4.9	June 7, 2012
1.26	695,666	2.3	November 29, 2009
1.75	10,000	3.1	September 23, 2010
1.80	136,000	2.7	March 27, 2010
1.95	333,265	2.5	January 20, 2010
$1.27	1,579,931	2.2	

All outstanding options are fully vested at July 31, 2007. The intrinsic value of outstanding options is approximately $48 at July 31, 2007.

Restricted Stock Awards

A summary of the status of the Company s nonvested shares as of July 31, 2007 and changes during the fiscal year ended July 31, 2007, is as follows:

Nonvested Shares	Shares		Weighted Average Grant-Date Fair Value
Nonvested at July 31, 2005		$	
Granted	2,325,000		0.61(1)
Vested	(84,163)		0.51
Nonvested at July 31, 2006	2,240,837		0.61
Granted	1,207,338		0.87
Vested	(1,010,837)		0.59
Nonvested at July 31, 2007	2,437,338	$	0.71

(1) The calculation of weighted average grant-date fair value includes the computed value of the option exchange, representing the difference between the fair value of the options surrendered and the fair value of the restricted

shares granted in the exchange. See below for a further description of the option exchange.

The Company granted restricted shares during fiscal year 2007 and 2006 as follows:

	Fiscal Year Ended July 31 2007	**Fiscal Year Ended July 31 2006**
Inducement grants	700,000	300,000
Employee bonuses	334,006	
Directors fees	173,332	
Option exchange		2,025,000
Total number of shares granted	1,207,338	2,325,000

Inducement Grants

The Company granted 700,000 and 300,000 restricted shares in the fiscal years ended July 31, 2007 and 2006, respectively, as inducement grants to the new Chief Operating Officer and members of his operational team. The

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

restrictions on the shares are scheduled to lapse based on service evenly over periods ranging from two to three years from the date of hire.

Employee Bonuses

The Company granted 324,006 restricted shares to employees for performance bonuses during the fiscal year ended July 31, 2007. The restrictions lapse based on service evenly over a two-year period from the date of grant. During the fiscal year ended July 31, 2007, the Company also granted 10,000 shares to an employee as a relocation bonus. Such shares will vest in three years from the date of grant.

Directors Fees

The Company granted 173,332 restricted shares to the four non-employee directors for annual retainer fees during the fiscal year ended July 31, 2007. The restrictions lapse evenly over a two-year period from the date of grant subject to each director standing for re-election in the year the shares are scheduled to vest.

Fiscal Year Ended July 31, 2006 Option Exchange

During the fiscal year ended July 31, 2006, the Compensation Committee approved an exchange of common shares for outstanding stock options held by various key employees and directors of the Company (the Option Exchange). The Option Exchange effectively cancelled stock option awards for 2,025,000 of the Company s common shares previously granted during fiscal years ended July 31, 2005 and 2006. The Option Exchange replaced the cancelled options with restricted stock awards of 2,025,000 of the Company s common shares. The restrictions on the shares of restricted stock are scheduled to lapse on three separate dates through January 1, 2009.

The Company accounted for the Option Exchange as a modification of the original shared-based payment awards (stock options) in accordance with SFAS No. 123(R). Accordingly, the Company recorded compensation expense based on the excess of the fair value of the restricted stock award grants over the fair value of the original award (stock options) measured immediately before the transaction based on current circumstances. The fair value of the restricted stock awards was determined based on the number of shares granted and the quoted price of the Company s common shares on the date of the grant of $1.42 per share. The value of the stock options surrendered was computed immediately before the modification using the Black-Scholes valuation model with the following assumptions:

Risk-free interest rate	4.75%
Expected dividend yield	Nil
Expected stock price volatility	94% 98%
Expected option remaining life	3.8 4.5 years

The risk-free interest rate used was based on the U.S. Treasury yield curve at the time of the transaction. The expected stock price volatility was based solely on the historical volatility of the Company s common stock during the historical period equivalent to the expected option life. In estimating expected volatility, the Company used a combination of the historical volatility of its stock for the period that it began trading on the American Stock Exchange and the historical volatility of its stock on the TSX Venture Exchange for the necessary period in order to reflect the expected remaining life of the stock options. The expected option life represents the remaining contractual life of the stock options surrendered.

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

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

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 July 31, 2007, there were $1,143 of unrecognized compensation cost related to restricted shares. The cost is expected to be amortized over a weighted average period of 0.8 years. The amount charged to expense related to the pro rata vesting of restricted shares was $838, $225 and $0 during the fiscal years ended July 31, 2007, 2006, and 2005, respectively.

Fully Vested Stock Awards

The Company granted fully vested shares during the fiscal years ended July 31, 2007 and 2006 as follows:

Purpose	**2007**	**2006**
Inducement grants	350,000	300,000
Employee bonuses	161,994	
Directors fees	86,668	140,000
Total number of shares granted	598,662	440,000

Inducement Grants

The Company granted 350,000 and 300,000 fully vested shares during the fiscal years ended July 31, 2007 and 2006, respectively, as inducement grants to our Chief Operating Officer and four new members of the Company s technical team. The grant of these fully vested shares resulted in the recognition of $326 and $426 of share-based compensation expense in the fiscal years ended July 31, 2007 and 2006, respectively.

Employee Bonuses

The Company granted 161,994 fully vested shares to employees for performance bonuses during the fiscal year ended July 31, 2007. The grant of these fully vested shares resulted in the recognition of $94 of share-based compensation expense in the fiscal year ended July 31, 2007. In addition, the Company accrued an additional $308 of share-based compensation expense at July 31, 2007 related to 312,500 shares issued to executives in August 2008 for fiscal year 2007 performance bonuses.

Directors Fees

The Company granted 86,668 fully vested common shares to the four non-employee directors for annual retainer fees during the fiscal year ended July 31, 2007. The Company also granted 140,000 fully vested shares to a newly appointed director during the fiscal year ended July 31, 2006. The grant of these fully vested shares resulted in the recognition of $50 and $199 of share-based compensation expense in the fiscal years ended July 31, 2007 and 2006, respectively.

Shares Surrendered

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 fiscal year ended July 31, 2007, the Company paid $137 in withholding taxes for participants in return for the surrender of 83,930 shares surrendered during the fiscal year ended July 31, 2007 and 157,494 shares to be surrendered during the first quarter of the fiscal year ended July 31, 2008. The amount paid by the Company for withholding taxes related to the shares surrendered was recorded as a decrease to additional paid-in capital in the fiscal year ended July 31, 2007.

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

15. 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 $5,846, 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 defendants filed a motion to dismiss the second amended complaint, which has been fully briefed and awaits a decision by the Court. We anticipate 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.

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.

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,

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

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 they were originally entered into. BPI has filed a motion to dismiss the lawsuit under the doctrine of estoppel by deed, arguing that ICG cannot challenge the leases because it acquired the CBM rights subject to those leases, as set forth in the deed from Addington and Meadowlark to ICG, the purchase agreement between those parties, and numerous bankruptcy court filings and orders associated with the approval of the sale. Addington was subsequently acquired by Nytis Exploration Company, LLC, which has intervened in the action and joined in BPI s motion. ICG has opposed BPI s motion, and the Court has held a hearing upon it. BPI has recently learned that, subsequent to filing suit, ICG may have transferred its Perry County coal and CBM rights to Arch Minerals, which is not currently a party to the lawsuit. It is unknown whether Arch will challenge the farm-out agreement. To date, BPI has drilled 10 pilot wells, one pressure observation well, one water disposal well and two test wells on the acreage covered by the farm-out agreement.

We believe that we will be successful in either having the case dismissed or 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.

16. OTHER INCOME (EXPENSE)

Other income (expense) consisted of the following for the fiscal years ended July 31, 2007, 2006 and 2005, respectively:

	Fiscal Year Ended July 31		
	2007	**2006**	**2005**
Legal settlement with Colt LLC	$	$ (2,950)	$
Gain on sale of investment in HCM		127	
Gain on sale of marketable securities trading			42
Distribution from HCM		51	7
Other		8	(14)
	$	$ (2,764)	$ 35

17. GAS PROPERTIES

The Company s gas properties are all located in the United States and consist solely of its CBM projects in the Illinois Basin. The Company s acreage rights in the Illinois Basin are currently divided into three projects: the Southern Illinois Basin Project; the Northern Illinois Basin Project; and the Western Illinois Basin Project.

Southern Illinois Basin Project

The Company s CBM rights in the Southern Illinois Basin Project cover 10,000 acres in the southern part of the Illinois Basin. The Company holds its CBM rights on this acreage pursuant to a purchase agreement under which it acquired the CBM estate in a settlement with its former lessor, the owner of the coal rights. Under the terms of the deed covering this acreage, the Company s right to drill for and produce CBM takes precedence over coal mining operations for as long as CBM is being produced from the acreage. However, the owner of the coal rights has the right to acquire any CBM wells located in these 10,000 acres. If the coal rights owner exercises this option, it will be required to (i) immediately plug any such well so acquired and (ii) pay the fair market value (as established by a mutually agreed upon expert) of such well.

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

In addition to the GasRock royalties, the Company is currently paying royalties of 3.03% on its production at this project. The GasRock royalties will also apply to the Company s acreage rights discussed below at the time the Company produces and sells CBM from the applicable acreage.

The Company commenced sales of gas from the initial pilot production wells on this project in January 2005. As of July 31, 2007, the Company has drilled 131 wells at this project. These wells consist of 91 productive wells, six shut-in wells, four divested wells (as a result of the Colt LLC settlement), nine plugged wells, two disposal wells, one pressure observation well, and 18 wells that have been drilled but are not yet in production. Most of the productive wells drilled at this project were initially completed in a limited number of seams, intentionally excluding other seams. The Company s intention when it drilled these wells was to gather as much geological information as it could about CBM and dewatering characteristics of individual coal seams. During fiscal year 2006, the Company completed additional seams in most of these wells to begin dewatering and producing CBM from the additional seams penetrated by these wells. During fiscal year 2007, the Company determined it was beneficial to complete additional seams in the remaining wells, which it plans to do in fiscal year 2008.

All of the Company s proved reserves are currently located at its Southern Illinois Basin Project.

Northern Illinois Basin Project

The Company s CBM rights in the Northern Illinois Basin Project cover 366,364 acres in Montgomery, Shelby, Christian, Fayette and Macoupin Counties in Illinois, which are located in the north central part of the Illinois Basin. The Company holds its CBM rights on this acreage pursuant to mineral leases and a farm-out agreement.

Montgomery County Lease

The lease agreement with Montgomery County covers 133,788 acres of CBM rights in Montgomery County, Illinois. The lease agreement extends until November 27, 2010. After the initial term of the agreement, the Company can continue to hold the lease as long as the Company is producing CBM from the covered acreage. Under the lease agreement, the Company is required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage.

Shelby County Lease

The lease agreement with Shelby County covers 63,250 acres of CBM rights in Shelby County, Illinois. The lease agreement extends until November 12, 2008. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage, with each productive vertical well holding 320 acres and each productive horizontal well holding 1,920 acres. The Company is required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage.

IEC (Montgomery), LLC Lease

The lease agreement with IEC (Montgomery), LLC covers approximately 102,000 acres of CBM rights in Christian, Fayette, Montgomery and Shelby Counties in Illinois. The lease agreement extends until April 26, 2026. After the initial term of the agreement, the Company can continue to hold the lease as to each acreage block where it is producing CBM in commercial quantities. The Company is required to pay royalties to the lessor on the Company s gross proceeds from the sale of CBM produced from the covered acreage at rates ranging up to 12.5%.

Christian Coal Holdings, LLC Lease

The lease agreement with Christian Coal Holdings, LLC covers approximately 12,040 acres of CBM rights in Christian and Montgomery Counties in Illinois. The lease agreement extends until April 26, 2026. After the initial term of the agreement, the Company can continue to hold the lease as to each acreage block where it is producing

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

CBM in commercial quantities. The Company is required to pay royalties to the lessor on the Company s gross proceeds from the sale of CBM produced from the covered acreage at a rate of 12.5%.

Christian County Lease

The lease agreement with Christian County covers approximately 14,033 acres of CBM rights in Christian County, Illinois. The lease agreement extends until January 20, 2012. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage. Under the lease agreement, the Company is required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage.

Addington Exploration, LLC (Macoupin County) Farm-out Agreement

Also included in the Northern Illinois Basin Project are 41,253 acres of CBM rights in Macoupin County, Illinois, which the Company can earn under a farm-out agreement with Addington Exploration, LLC, as described below.

Under the lease agreements with Montgomery, Shelby, and Christian Counties, the Company s right to drill for and produce CBM is expressly subject to the mining of coal on the covered acreage. The Company may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining operations will be undertaken.

Under the lease agreements with IEC (Montgomery), LLC and Christian Coal Holdings, LLC, any drilling operations that the Company sets-up can be displaced by coal mining operations. However, the lessor is required to provide the Company with a mine plan for the leased acreage indicating the acreage blocks that the lessor plans to mine and the order of priority for the acreage blocks that it plans to mine. If the lessor displaces a well ahead of the schedule outlined in the mine plan, the lessor may be required to reimburse the Company for the cost of plugging the well and, depending on how long the well has been in production and the cumulative gross income generated by the well, the value of the CBM that could be recovered from the well in the remainder of an eight-year term.

As of July 31, 2006, the Company completed drilling of a 10-well pilot program at this project referred to as the Shelby Pilot. In the fiscal year ended July 31, 2007 at the Shelby Pilot, the Company added one pressure observation well and drilled two additional producers that are not currently completed. Also during the fiscal year ended July 31, 2007, the Company drilled two new test wells in other parts of the Shelby County acreage block. During the fourth quarter of the fiscal year ended July 31, 2007, the Company announced its decision to continue production activities at the Shelby Pilot, while deferring additional development pending further production and pressure information.

As of July 31, 2007, the Company drilled and completed a second 10-well pilot project, the Macoupin Pilot, in the Northern Illinois Basin Project. Those wells have just started the dewatering process. The Macoupin Pilot also includes one pressure observation well and one disposal well. The Company currently has no proved reserves located at the Northern Illinois Basin Project.

Western Illinois Basin Project

The Company s CBM rights in the Western Illinois Basin Project cover 135,948 acres in Clinton, Washington, Marion and Perry Counties in Illinois, which are located in the northwestern part of the Illinois Basin. The Company holds its CBM rights on this acreage pursuant to mineral leases and a farm-out agreement.

Clinton County Lease

The lease agreement with Clinton County covers 55,900 acres of CBM rights in Clinton County, Illinois. The lease agreement extends until October 24, 2010. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage. The Company is required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage.

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

Washington County Lease

The lease agreement with Washington County covers 39,169 acres of CBM rights in Washington County, Illinois. The lease agreement extends until September 9, 2011. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage, with each productive vertical well holding 320 acres and each productive horizontal well holding 1,920 acres. Under the lease agreement, the Company is required to pay royalties to the lessor from the Company s gross proceeds from the sale of CBM produced from the covered acreage. The royalty is equal to 12.5% or 6.25% of the Company s gross proceeds, depending on whether it is determined that Washington Counties CBM rights, if any, are derived from coal rights or oil and gas rights.

Marion County Lease

The lease agreement with Marion County covers 17,882 acres of CBM rights in Marion County, Illinois. The lease agreement extends until June 7, 2012. After the initial term of the agreement, the Company can continue to hold the lease as long as it is producing CBM from the covered acreage. Under the lease agreement, the Company will be required to pay royalties to the lessor equal to 12.5% of the Company s gross proceeds from the sale of CBM produced from the covered acreage. If the Company does not commence exploration of CBM within one year from the commencement of the lease, the Company will be required to pay advance royalties to the lessor equal to $8,941 for each one-year period that the Company delays commencing exploration. Any payment of advance royalties can be credited against royalties that may later become payable to the lessor from the production of CBM.

Addington Exploration, LLC (Perry County) Farm-out Agreement

Also included in the Western Illinois Basin Project are 22,997 acres in Perry County, Illinois, which the Company can earn under a farm-out agreement with Addington Exploration, LLC, as described below.

As of July 31, 2007, the Company has drilled four test wells at the Western Illinois Basin Project from which the Company is still gathering and evaluating data. The Company currently has no proved reserves located at the Western Illinois Basin Project.

Addington Exploration, LLC Farm-out Agreement

The Company entered into a farm-out agreement with Addington Exploration, LLC covering 41,253 acres of CBM rights in Macoupin County, Illinois (part of the Northern Illinois Basin Project) and 22,997 acres of CBM rights in Perry County, Illinois (part of the Western Illinois Basin Project) that Addington controls pursuant to coal seam gas leases. The farm-out agreement provides for an initial 36-month evaluation period, during which the Company may test and evaluate the covered properties. The 36-month evaluation period can be extended by the Company on unearned acreage through the payment of a fee equal to $0.50 per acre, increasing over five years to $2.50 per acre. For each vertical and horizontal well that the Company places into production during the term of the agreement, Addington will assign to the Company its CBM rights covering the surrounding 160 acres penetrated by one of the Company s wells. The Company plans to extend the 36-month evaluation period on unearned acreage when it expires in November 2007.

The Company is required to pay Addington a royalty equal to 3% of the Company s proceeds from the sale of CBM produced from the covered acreage. In addition, the Company must pay royalties totaling 12.5% to the lessors under the coal seam gas leases underlying this farm-out agreement.

Under the lease agreements with Washington and Marion Counties, the Company s right to drill for and produce CBM is expressly subject to the mining of coal on the covered acreage. The Company may not interfere with any existing coal mining operations and, under certain circumstances, may be required to cease drilling in locations where coal mining operations will be undertaken. Under the lease agreement with Clinton County, coal mining rights granted to third parties do not take precedence over the Company s CBM operations.

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

The following table sets forth a summary of gas property costs not being amortized at July 31, 2007, by the fiscal year in which such costs were incurred:

	Total	2007	2006	2005	2004 and Prior
Property acquisition costs	$ 215	$ 37	$	$ 151	$ 27
Exploration and development, net of transfers to proved oil and gas properties	8,318	5,127	2,446	742	3
	$ 8,533	$ 5,164	$ 2,446	$ 893	$ 30

No interest has been capitalized and included in the cost of unproved properties as of July 31, 2004 or in the fiscal years ended July 31, 2005, 2006 and 2007, as such amounts were not material. The Company expects to include the costs associated with unproved properties in its amortization computation over the next one to three years when future development of the projects is expected to result in additional reserves being classified as proved. Depletion expense related to proved gas properties was $524, $312 and $63 or $2.83/Mcf, $2.31/Mcf and $3.48/Mcf in the fiscal years ended July 31, 2007, 2006 and 2005, respectively.

18. 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 received approximately $12, $70 and $59 in expense reimbursement related to this arrangement during the fiscal years ended July 31, 2007, 2006 and 2005, 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 approximately $0, $237 and $147 during the fiscal years ended July 31, 2007, 2006 and 2005, respectively.

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 approximately $15, $293 and $0 for executive placement services during the fiscal years ended July 31, 2007, 2006 and 2005, respectively.

19. SUPPLEMENTAL GAS DATA

The following unaudited information was prepared in accordance with Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities, and related accounting rules.

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves developed by our independent reservoir engineer consultant.

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

Summary of Changes in Proved Reserves (Unaudited)

	Year Ended July 31		
	2007 MMcf	**2006 MMcf**	**2005 MMcf**
Proved reserves			
Beginning of year	14,718	10,292	
Purchase (sale) of reserves in place	(885)	2,229	
Extensions and discoveries	5,434	4,528	10,326
Revisions of previous estimates	(2,808)	(2,186)	
Production	(185)	(145)	(34)
End of year	16,274	14,718	10,292
Proved developed reserves			
Beginning of year	8,983	2,971	
End of year	10,639	8,983	2,971

Capitalized Costs Related to Gas Producing Activities

The capitalized costs relating to gas producing activities and the related accumulated depletion, depreciation, amortization and impairment as of July 31, 2007 and 2006 were as follows:

	Fiscal Year Ended July 31	
	2007	**2006**
Capitalized costs:		
Proved oil and gas properties	$ 29,852	$ 25,440
Unproved oil and gas properties	8,533	3,368
Support equipment	1,293	1,047
Total capitalized costs	39,678	29,855
Less: Accumulated DD&A and ceiling write-down	(13,962)	(923)
Net capitalized costs	$ 25,716	$ 28,932

Costs Incurred in Gas Exploration and Development Activities

Costs related to gas activities of the Company were incurred as follows for the fiscal years ended July 31, 2007, 2006 and 2005:

	Fiscal Year Ended July 31		
	2007	**2006**	**2005**
Property acquisition proved	$ 11	$	$
Property acquisition unproved	37		342
Exploration	4,351		744
Development	5,178	14,018	6,766
Support equipment	245	287	238
	$ 9,822	$ 14,305	$ 8,090

F-32

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

All costs incurred on unproved properties, other than property acquisition costs, are classified as exploration costs until such time as the properties can be evaluated. Prior to the fiscal year 2005, the Company s properties were all considered unproved and all costs to drill and equip wells and gain access to and prepare well locations for drilling were classified as exploration costs.

Results of Operations from Gas Producing Activities

The table below sets forth the Company s results of operations from gas producing activities for the fiscal years ended July 31, 2007, 2006 and 2005. The Company commenced production and sales of gas during the fiscal year ended July 31, 2005.

	Fiscal Year Ended July 31		
	2007	**2006**	**2005**
Gas revenues	$ 1,204	$ 1,126	$ 118
Production costs	(1,608)	(971)	(307)
Depreciation, depletion, amortization and ceiling write-down	(12,439)	(537)	(239)
Pre-tax operating loss	(12,843)	(382)	(428)
Income taxes			167
Loss from gas producing activities	$ (12,843)	$ (382)	$ (261)

The following estimates of proved reserve quantities and related standardized measure of discounted net cash flows are estimates only and do not purport to reflect realizable values or fair market values of the Company s reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company s reserves are located in the United States.

Proved reserves are estimated reserves of natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment and operating methods.

The standardized measure of discounted future net cash flows is computed by applying year-end prices of gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less the tax bases of the properties and available credits and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows. The gross average price per MMBtu used at July 31, 2007 and 2006 was $6.51 and $8.05, respectively, based on the Henry Hub gas spot price on those dates. The prices were adjusted for the Company s contractual basis differential, lease usage, shrinkage and conversion from MMBtu to Mcf to arrive at average net price per Mcf of $5.29 and $7.22 at July 31, 2007 and 2006, respectively. At July 31, 2005, the price was adjusted only for conversion from MMBtu to Mcf to arrive at a net price of $7.44 per Mcf.

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas Reserves (Unaudited)

The standardized measure of discounted cash flows related to proved gas reserves at July 31, 2007, 2006 and 2005 were as follows:

	July 31		
	2007	2006	2005
Future cash inflows	$ 86,039	$ 106,221	$ 76,608
Future production costs and taxes	(33,728)	(24,937)	(10,181)
Future development costs	(9,406)	(8,930)	(7,824)
Future income tax expenses		(15,775)	(14,663)
Net future cash flows	42,905	56,579	43,940
Discounted at 10% for estimated timing of cash flows	(25,722)	(23,845)	(20,872)
Standardized measure of discounted future net cash flows	$ 17,183	$ 32,734	$ 23,068

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas Reserves (Unaudited)

The primary changes in the standardized measure of discounted future net cash flows for the fiscal years ended July 31, 2007, 2006 and 2005 were as follows:

	Year Ended July 31		
	2007	2006	2005
Standardized measure, beginning of year	$ 32,734	$ 23,068	$
Sales, net of production costs and taxes	404	(156)	189
Extensions and discoveries	12,167	14,633	27,758
Purchases (sales) of reserves in place	(1,981)	7,206	
Net changes in prices and production costs	(23,664)	(5,606)	
Net changes in future development costs	(439)	(1,023)	(5,541)
Revisions of quantity estimates	(6,288)	(7,063)	
Interest factor accretion of discount	2,385	3,077	
Net change in income tax	2,684	(651)	
Net change in production rates (timing) and other	(819)	(751)	662
Net increase (decrease)	(15,551)	9,666	23,068
Standardized measure, end of year	$ 17,183	$ 32,734	$ 23,068

Table of Contents

BPI ENERGY HOLDINGS, INC.

Notes to Consolidated Financial Statements (Continued)

20. SELECTED QUARTERLY DATA (UNAUDITED)

Summarized below are the unaudited results of operations by quarter for the fiscal years ended July 31, 2007 and 2006:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Fiscal 2007:				
Gas sales	$ 294	$ 247	$ 335	$ 328
Lease operating expenses	336	528	412	332
Net loss	(2,745)	(1,779)	(2,070)	(14,047)
Basic and diluted loss per common share	$ (.04)	$ (.03)	$ (.03)	$ (.20)
Fiscal 2006:				
Gas sales	$ 210	$ 327	$ 263	$ 326
Lease operating expenses	161	301	291	218
Net loss	(1,193)	(854)	(4,942)	(1,847)
Basic and diluted loss per common share	$ (.03)	$ (.01)	$ (.14)	$ (.03)

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

By: /s/ James G. Azlein

James G. Azlein,
President and Chief Executive Officer

Date: October 29, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title
/s/ James G. Azlein	President, Chief Executive Officer and Director
James G. Azlein	
/s/ Randy Elkins	Controller and Acting Chief Financial Officer (Principal Financial and Accounting Officer)
Randy Elkins	
/s/ James E. Craddock*	Chief Operating Officer and Director
James E. Craddock	
/s/ Dennis Carlton*	Director
Dennis Carlton	
/s/ David E. Preng*	Director
David E. Preng	
/s/ Costa Vrisakis*	Director
Costa Vrisakis	

*By: /s/ James G. Azlein

James G. Azlein,Attorney-in-Fact for the directors signing in the capacities indicated

Date: October 29, 2007

Table of Contents

EXHIBIT INDEX

Number	Description
3.1	Articles of Incorporation of BPI Energy Holdings, Inc. (Incorporated by reference to Appendix A of the Proxy Statement filed by BPI Energy Holdings, Inc. with the SEC on January 12, 2006).
4.1	Incentive Stock Option Plan of BPI Energy Holdings, Inc., dated as of December 16, 2002.(*)(#)
4.2	BPI Energy Holdings, Inc. Amended and Restated 2005 Omnibus Stock Plan (Incorporated by reference to Appendix A of the Proxy Statement filed by BPI Energy Holdings, Inc. with the SEC on November 21, 2006).(#)
4.3	Stock Purchase Agreement, dated September 20, 2005, by and among BPI Energy Holdings, Inc. and the investors party thereto.(***)
10.1	Common Stock Purchase Warrant issued by BPI Energy Holdings, Inc. on December 31, 2004 to Sanders Morris Harris, Inc.(*)
10.2	Common Stock Purchase Warrant issued by BPI Energy Holdings, Inc. on January 12, 2005 to Sanders Morris Harris, Inc.(*)
10.3	Form of Warrant Certificate issued by BPI Energy Holdings, Inc. in its December 2004/January 2005 private placement.(*)
10.4	Advancing Term Credit Agreement, dated as of July 27, 2007, by and between BPI Energy, Inc. and GasRock Capital LLC (Filed as Exhibit 10.1 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on August 2, 2007 and incorporated herein by reference).
10.5	Conveyance of Royalty Interest and Overriding Royalty Interest, dated as of July 27, 2007, from and by BPI Energy, Inc. to and in favor of GasRock Capital LLC (Filed as Exhibit 10.2 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on August 2, 2007 and incorporated herein by reference).
10.6	Mineral Lease, dated as of November 12, 2003, by and between BPI Energy, Inc. and the County of Shelby, Illinois (Northern Illinois Basin Project).(*)
10.7	Farm-out Agreement, dated as of November 2, 2004, by and between BPI Energy, Inc. and Addington Exploration, LLC (Northern Illinois Basin and Western Illinois Basin Projects).(*)
10.8	Mineral Lease, dated as of October 25, 2005, by and between BPI Energy, Inc. and the County of Clinton, Illinois (Western Illinois Basin Project).( )
10.9	Coal Seam Gas Lease Agreement, dated April 26, 2006, by and between BPI Energy, Inc. and IEC (Montgomery), LLC (Northern Illinois Basin Project) (Filed as Exhibit 10.1 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on April 28, 2006 and incorporated herein by reference).
10.10	Coal Seam Gas Lease Agreement, dated April 26, 2006, by and between BPI Energy, Inc. and Christian Coal Holdings, LLC (Northern Illinois Basin Project) (Filed as Exhibit 10.2 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on April 28, 2006 and incorporated herein by reference).
10.11	Settlement Memorandum of Understanding by and among BPI Energy, Inc., Colt LLC, AFC Coal Properties, Inc., American Premier Underwriters, Inc. and Central States Coal Reserves of Illinois, LLC, dated June 13, 2006 (Filed as Exhibit 10.1 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on June 15, 2006 and incorporated herein by reference).
10.12	Settlement and Mutual Release Agreement, dated June 23, 2006, by and among BPI Energy, Inc., for itself and as successor by merger or otherwise to Methane Management, Inc. and BPI Industries Inc., Colt LLC, AFC Coal Properties, Inc., American Premier Underwriters, Inc. and Central States Coal Reserves of Illinois, LLC (Filed as Exhibit 10.1 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on June 27, 2006 and incorporated herein by reference).
10.13	Purchase and Sale Agreement, dated June 23, 2006, by and between Colt LLC and BPI Energy, Inc. (Filed as Exhibit 10.2 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on June 27, 2006 and incorporated herein by reference).

10.14	Termination Agreement, dated June 23, 2006, by and between BPI Energy, Inc., for itself and as successor by merger or otherwise to Methane Management, Inc. and BPI Industries Inc., Colt LLC, AFC Coal Properties, Inc., American Premier Underwriters, Inc. and Central States Coal Reserves of Illinois, LLC, for itself and its predecessor Peabody Development Land Holdings, LLC (Filed as Exhibit 10.3 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on June 27, 2006 and incorporated herein by reference).

Number	Description
10.15	Mineral Lease, dated as of September 9, 2006, by and between BPI Energy, Inc. and the County of Washington, Illinois (Western Illinois Basin Project) (Filed as Exhibit 10.12 to Form 10-K of BPI Energy Holdings, Inc. filed with the SEC on October 30, 2006 and incorporated herein by reference).
10.16	Mineral Lease, dated as of January 5, 2007, by and between BPI Energy, Inc. and the County of Christian, Illinois (Northern Illinois Basin Project).( )
10.17	Mineral Lease, dated as of June 7, 2007, by and between BPI Energy, Inc. and the County of Marion, Illinois (Western Illinois Basin Project).( )
10.18	Ratification of Mineral Lease, dated July 10, 2007, by and between BPI Energy, Inc. and the County of Montgomery, Illinois (Northern Illinois Basin Project).( )
10.19	Supplemental Memorandum of Mineral Lease, dated August 14, 2007, by and between BPI Energy, Inc. and the County of Montgomery, Illinois (Northern Illinois Basin Project).( )
10.20	Base Contract for Sale and Purchase of Natural Gas, dated as of December 1, 2004, by and between BPI Energy Holdings, Inc. and Atmos Energy Marketing, LLC.(**)
10.21	Transaction Confirmation for the Sale and Purchase of Natural Gas, dated January 30, 2006, by and between BPI Energy Holdings, Inc. and Atmos Energy Marketing, LLC. (Filed as Exhibit 10.22 to Form 10-K of BPI Energy Holdings, Inc. filed with the SEC on October 30, 2006 and incorporated herein by reference).
10.22	Agreement, dated as of April 17, 2004, by and between BPI Energy Holdings, Inc. and James G. Azlein.(*)(#)
10.23	Employment Letter Agreement, dated as of January 31, 2005, by and between BPI Energy Holdings, Inc. and Randy Elkins.(*)(#)
10.24	Separation Agreement and Waiver and Release by and between BPI Energy Holdings, Inc. and George J. Zilich, dated October 12, 2006 (Filed as Exhibit 10.1 to Form 8-K of BPI Energy Holdings, Inc. filed with the SEC on October 16, 2006 and incorporated herein by reference).(#)
10.25	BPI Energy Holdings, Inc. Senior Executive Severance Plan, dated June 7, 2007 (Filed as Exhibit 10.1 to Form 10-Q of BPI Energy Holdings, Inc. filed with the SEC on June 13, 2007 and incorporated herein by reference).(#)
10.26	BPI Energy Holdings, Inc. Key Employee Severance Plan, dated June 7, 2007 (Filed as Exhibit 10.2 to Form 10-Q of BPI Energy Holdings, Inc. filed with the SEC on June 13, 2007 and incorporated herein by reference).(#)
21.1	List of Subsidiaries.( )
23.1	Consent of Schlumberger Technology Corporation.( )
23.2	Consent of Meaden & Moore, Ltd.( )
24.1	Power of Attorney.( )
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 Chief Executive Officer (Principal Executive Officer).( )
32.2	Section 906 Certification of the Acting Chief Financial Officer (Principal Financial Officer).( )

(*) Incorporated by reference to the S-1 Registration Statement filed by BPI Energy Holdings, Inc. with the SEC on June 3, 2005 (File No. 333-125483).

(**) Incorporated by reference to Amendment No. 2 to the S-1 Registration Statement filed by BPI Energy Holdings, Inc. with the SEC on September 6, 2005 (File No. 333-125483).

(***) Incorporated by reference to Amendment No. 3 to the S-1 Registration Statement filed by BPI Energy Holdings, Inc. with the SEC on October 28, 2005 (File No. 333-125483).

( ) Filed herewith.

(#) Management contract or compensatory plan or arrangement.