PRB Energy, Inc.
Form 10-K
March 30, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: 001-32471

PRB ENERGY, INC.

(Exact Name of Registrant as specified in its Charter)

Nevada (State or other jurisdiction of incorporation or organization)	**20-0563497** (IRS Employer Identification No.)
1875 Lawrence Street, Suite 450 **Denver, Colorado** (Address of Principal Executive Offices)	**80202** (Zip Code)

Registrant s Telephone Number, including area code: **(303) 308-1330**

(Former name, former address and former fiscal year, if changed since last report): **None**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Exchange on Which Registered**
Common Stock, $.001 par value	American Stock Exchange

Securities registered pursuant to Section 12(g) of the 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 x

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

Indicate by check mark whether registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant 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.

Large accelerated filer o Accelerated filer o Non-accelerated filer x

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

The aggregate market value of the registrant s common stock held by non-affiliates of the registrant as of June 30, 2006 was $33,549,628 computed by reference to the price at which the registrant s common stock was last traded on that date.

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Class	Outstanding at March 23, 2007
Common Stock, $.001 par value	**8,601,994 shares**

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive proxy statement to be delivered to stockholders in connection with the Annual Meeting of stockholders are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

Cautionary Note Regarding Forward-Looking Statements

The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements made by or on our behalf. We may from time-to-time make statements that are forward-looking, including statements contained in this Annual Report on Form 10-K and other filings with the Securities and Exchange Commission (the SEC) and in reports to our shareholders. Such statements may, for example, express expectations or projections about future actions that we may take or about developments beyond our control including changes in domestic or global economic conditions. These statements are made on the basis of our management s views and assumptions as of the time the statements are made and we undertake no obligation to update these statements. Our actual results may differ significantly from the results discussed in the forward-looking statements. General factors that might cause such differences include, but are not limited to:

- Changes in gas prices due to volatility of the market
- Our ability to evaluate our future performance due to limited operating history
- The continuance of reserve replacement through development of existing properties in order to sustain production
- Our ability to insure against liabilities associated with properties or obtain protection from sellers against them
- Our ability to evaluate projections of acquired property production
- Our ability to acquire or transact business due to requirements of significant external capital changing our risk and property profile.
- Our ability to manage the risks inherent in operations of gas properties
- Our exposure to guaranteed indebtedness of our subsidiaries and the covenants in the agreements governing that debt
- Our ability to manage due to covenants limiting discretion of management in operating our business
- Our ability to perform certain development operations depends on financing through equity or debt
- Our ability to successfully integrate future acquisitions
- Our ability to attract and retain professional personnel

For more information on these and other risk factors that may affect our business, refer to Item 1A Risk Factors included in this Annual Report on Form 10-K.

PART I

ITEM 1. BUSINESS

Description of Business

PRB Energy, Inc. and its subsidiaries (PRB, PRB Energy, the Company, us, our or we) operate as an independent energy company engag the acquisition, exploitation, development and production of natural gas and oil. In addition, we provide gas gathering, processing and compression services for properties we operate and for third-party producers. We were initially incorporated in Nevada under the name PRB Transportation, Inc. in December 2003. In January 2004, we acquired certain gas gathering and related assets of our predecessor company, TOP Gathering, LLC (TOP), a privately held Colorado company formed in 2001. On June 14, 2006, we changed our name to PRB Energy, Inc. Our common stock is traded on the American Stock Exchange (AMEX) under the ticker symbol PRB.

PRB Energy operates as two business segments through two wholly-owned subsidiaries, PRB Oil and Gas, Inc., a Colorado corporation, a gas and oil exploitation and production company (E&P), formed in July, 2005, and PRB Gathering, Inc., a Colorado corporation, a gathering and processing company (G&P), formed in August 2006. We conduct our business activities in Wyoming, Colorado and Nebraska.

Recent Developments

Capital Lease On February 12, 2007, we entered into a five-year lease agreement with J-W Power Company (J-W), effective January 24, 2007. Under the terms of the agreement, J-W will supply us with gas compression equipment and related services. The compression equipment will service our gas gathering pipelines in the Powder River Basin.

The lease has been recorded in our February 2007 financial statements as a capital lease asset of $3 million, along with the corresponding liability of the same amount, which represents the estimated fair value of the property. In addition, a cash prepayment of $650,000 was made to J-W for future maintenance repairs in connection with the lease. The capital lease and prepayment will be amortized as expense over the term of the lease. Monthly lease payments, including interest and executory (sales tax and environmental fees) expenses, will reduce the liability.

Registration of Additional Shares of PRB Energy, Inc. Common Stock In connection with the borrowing of $15 million from 2 private lenders for the Denver-Julesburg Basin acquisition on December 28, 2006, we issued 1,250,000 shares of PRB Energy common stock to the lenders. We also entered into a Registration Rights Agreement with the lenders requiring us to file a registration statement registering the shares issued to the lenders for resale on behalf of them under the Securities Act of 1933. We filed the registration statement on Form S-3 with the SEC on February 2, 2007. The SEC staff comments have been received and we responded to them on March 22, 2007.

2006 Acquisitions and Divestitures

Pennaco Assets On June 30, 2006, we acquired working interests in approximately 590 gross (531 net) coal-bed methane (CBM) wells on approximately 29,000 acres located in the Powder River Basin of Wyoming from Pennaco Energy, Inc. (Pennaco). The purchase price of the acquired interests was approximately $600,000 and the effective date was July 1, 2006. As part of the purchase agreement, we issued a $3 million reducing letter of credit for the benefit of Pennaco to guarantee the funding of the future liability of the plugging costs of wells being purchased from Pennaco. The asset retirement obligation of these wells has been recorded on the balance sheet for $2 million based on the discounted present value of the future liability, as further reflected in Note 3 Concentration of Credit Risk to our consolidated financial statements included in Item 8 of this report. The letter of credit is collateralized by a $3 million certificate of deposit (CD) and is considered restricted cash for purposes of available working capital. The restricted amount of the CD will be released at the same rate annually that the letter of credit is reduced (refer to management s discussion on Liquidity and Capital Resources in the Management s Discussion and Analysis section in this report).

Of the 590 gross wells acquired, fewer than 130 wells were commercially producing natural gas. We currently have approximately 220 wells on production or dewatering.

Denver-Julesburg Basin (D-J Basin) On December 28, 2006, we closed on the acquisition of 13 wells, consisting of 12 gas wells and 1 water disposal well, and approximately 330,000 net acres in northeastern Colorado and southwestern Nebraska, to which we refer to as the Properties, for $11.7 million in cash. The sellers of the Properties were Lance Oil & Gas Company, Inc. and Western Gas Resources, Inc. In addition to the producing wells, the acquisition includes approximately 159 drilling locations as identified by 3-D seismic and the license to 85 square miles of proprietary 3-D seismic and 115 miles of proprietary 2-D seismic.

On December 28, 2006, in connection with the acquisition of the Properties, we entered into a securities purchase agreement (SPA) with DKR Soundshore Oasis Holding Fund Ltd. and West Coast Opportunity Fund, LLC, which we refer to as the lenders. Pursuant to the SPA, in exchange for $15 million of proceeds, we issued and sold to the lenders $15 million of Senior Secured Debentures (the Debentures) and we issued and sold to the lenders 1,250,000 shares of common stock. The Debentures mature and are due and payable on August 31, 2008 and bear interest at 13% per annum, which is due and payable quarterly. Subject to certain conditions, the Debentures can be prepaid by us with a premium for early prepayment of 110% of the principal amounts. Upon the occurrence of an event of default, as described in the Debentures, the payment of the principal amounts may be accelerated and the interest rate applicable to the principal amounts will be increased to 18% per annum during the period the default exists. A majority of the proceeds received from the lenders was used for the acquisition of the properties with the balance to be used for general corporate purposes.

Pursuant to the terms of a pledge and security agreement (PSA) entered into by the Company and the lenders, the Debentures are collateralized by substantially all of our assets, except for certain excluded assets as described in the PSA. Pursuant to the terms of the PSA, the lenders are entitled to foreclose on, and take possession of, the pledged assets if an event of default occurs. In addition, pursuant to the terms of the secured guaranty, the Company has agreed to jointly and severally guarantee performance under the Debentures and the other transaction documents.

The shares of our common stock issued to the lenders at the time they were issued represented 14.5% of our outstanding common stock on a fully diluted basis. We also entered into a registration rights agreement with the lenders requiring us to file a registration statement registering the shares issued to the lenders for resale on behalf of them under the Securities Act of 1933. In the event that the registration statement is not declared effective within one hundred-fifty (150) days of December 28, 2006 (by May 28, 2007) or the effectiveness of the registration statement is not maintained, we are obligated to pay, on a pro rata basis, to each holder of the shares of common stock issued to the lenders certain delay payments described in the registration rights agreement. Such delay payments shall not exceed, in the aggregate, $750,000. A registration statement was filed to register these shares with the SEC on February 2, 2007.

Recluse Gathering System In the first quarter of 2006, we acquired 2 gas gathering systems in the Recluse area of Wyoming (together our Recluse gathering system) for approximately $1.5 million. Also, in 2 separate transactions totaling $183,000, we acquired a combination of working interests ranging from 7.5% to 15% in the development of approximately 5,600 net acres in the Recluse area that offers us the opportunity to expand both our development and production and gathering and processing activities in this area.

On August 4, 2006, we closed an acquisition from Maverick Pipeline LLC of approximately 70 miles of gathering lines in the Recluse area which will provide additional opportunities for expanding gathering services to producers in the 100,000 acres surrounding the pipelines. The transaction was effective August 1, 2006 and the $428,000 purchase price was paid in cash.

Sale of TOP Gathering System As of September 1, 2006 we sold certain gas gathering assets referred to as the TOP Gathering

System to Arete Industries, Inc. for $330,000 in cash. The net gain on the sale of $308,000 is reflected in Other Income in the December 31, 2006 consolidated financial statements included in Item 8 of this report.

Competition

Exploitation and Production (E&P) The Company s gas exploitation activities take place in a highly competitive and speculative business atmosphere. As an independent producer we have little control over the price we receive for our natural gas. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to our customers. In seeking suitable oil and gas properties for development or acquisition, we compete with a number of other companies, including large oil and gas companies and other independent operators with greater financial resources. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Gas Gathering and Processing (G&P) Gas gathering systems are generally either acquired or developed pursuant to long-term contracts with gas producers or the shippers they service. The contracts generally run over a period of time which approximates a majority of the economic life of the gas producers wells. We believe that having such contracts and an existing gathering system in place provides a significant barrier of entry to third parties seeking to compete with us upon the expiration of our contracts.

When developing new gathering systems in areas where we do not have the advantage of existing systems in proximity to the development, we may be competing with other gathering system operators or the producer may elect to construct and own the system. In the case of other gathering system operators, many possess financial, technical and personnel resources substantially greater than ours.

Environmental Regulation

All of the water produced by our CBM wells is discharged on the surface. The discharge points are covered by approved discharge permits from the Wyoming Department of Environmental Quality (WDEQ). An ongoing requirement of maintaining compliance is regular monitoring of the water quality being discharged. We employ a rigorous program of water discharge permit approval and routine water discharge compliance monitoring.

We operate gathering systems in Wyoming and Colorado, for which proper construction permits were obtained prior to initial construction. We have operating permits in place, and we meet all requirements associated with operation and reporting associated with these permits. We have applied for two additional operating permits in the Recluse area, which we anticipate being issued in the second quarter of 2007.

Federal, state and local authorities extensively regulate the energy industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of gas production. Noncompliance with statutes and regulations may lead to substantial penalties, and the overall regulatory burden on the industry increases the cost of doing business and, in turn, decreases profitability.

Governmental authorities regulate various aspects of gas drilling and production, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment and restoration.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities in jurisdictions where we are engaged in development or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to governmental authorities and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and we could have to spend substantial amounts on investigations, litigation and remediation. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, may have a material adverse effect on us.

We have reflected in our consolidated financial statements a reserve for future capital expenditures for remediation costs at the end of the life of the wells and life of the gathering assets. Refer to Note 7 Asset Retirement Obligations to our consolidated financial statements in Item 8 of this report.

Intrastate Regulation

No regulatory body controls the gathering rates we may charge.

Safety and Maintenance

Exploitation and Production (E&P) We conduct safety training classes for all of our field employees dealing with oil and gas development and production. As of December 31, 2006, all field employees have participated in these classes and are in compliance with safety regulations.

Gas Gathering and Processing (G&P) With respect to certain gathering operations, we contract with third parties to perform preventive and normal maintenance on some of our gathering systems and make repairs and replacements when necessary or appropriate. On our behalf, third parties also conduct routine and required inspections of our gathering and other assets as required by applicable code or regulation. External coatings and cathodic protection systems are used to protect against external corrosion. The systems are continually monitored and tested, and the results recorded, to ensure the early identification of any problem that may arise. We have contracted a third party to provide the necessary training to our employees as required by the Occupational Safety and Health Administration.

Significant Contracts

Storm Cat Agreement Effective January 1, 2006, we entered into a gas gathering services agreement (the Agreement) with Storm Cat Energy Corporation (Storm Cat) which requires Storm Cat to pay us gas gathering fees on specific minimum volumes of gas whether or not those volumes are delivered and transported through our system. The Agreement has a 10-year term, of which the first 5 years are non-cancelable. The Agreement requires Storm Cat to make minimum payments in 2006 and during the first 3 years of the Agreement. The Agreement also provides for our gas gathering rates to decrease during the fourth and fifth years.

During the year ended December 31, 2006, we billed Storm Cat for actual volumes delivered. The Agreement allows for a cash true-up payment at each year-end if the annual volume commitment under the Agreement is not met. We recognize revenues based on our estimate of the average gas gathering rate during the non-cancelable term of the Agreement. Accordingly, we deferred the gas gathering fees as a non-current liability on our balance sheet at December 31, 2006.

Rocky Mountain Gas Agreement Refer to Item 3, Legal Proceedings of this report.

Major Customers

Exploitation and Production (E&P) We sold 22.2% of total consolidated revenue on a spot sale basis to United Energy Trading Company during the year ended December 31, 2006. We have the option to sell to a number of other marketing companies within the region.

Gathering and Processing (G&P) Our G&P systems service several customers in the Powder River Basin area of Wyoming. Storm Cat is our largest gathering and processing customer at approximately 21.2% of total consolidated revenue for the year ended December 31, 2006.

We do not believe the loss of either of the above major customers would have a material adverse affect on our financial position. Please refer to our consolidated financial statements included in Item 8 of this report.

Seasonality

Both E&P and G&P Business Segments Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and the warmer summer months. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal anomalies such as mild winters and summers sometimes lessen these fluctuations.

Employees

As of December 31, 2006, we had 26 full-time employees compared to December 31, 2005 when there were 18 full-time employees.

Access to Information

Our website address is www.prbenergy.com. We make available, free of charge, on the Investor Relations section of our website, our public informational releases, SEC annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K and all amendments to those reports, as soon as reasonably practicable after these reports are electronically filed with or furnished to the SEC. We do not intend for information contained in our website to be part of this report.

ITEM 1A. RISK FACTORS

You should carefully consider the following risks and other information contained in this report. These risks could materially affect our business, results of operations or financial condition and cause the trading price of our common stock to decline. The risks and uncertainties described below are not the only risks facing us. Additional risks not presently known to us or which we consider immaterial based on information currently available to us may also materially adversely affect us. If any of the following risks or uncertainties actually occurs, our business, financial condition and results of operations could be adversely affected.

Risks Related to the Natural Gas Industry and Our Business

We have incurred net losses from operations since inception. Our future performance is difficult to evaluate because we have a limited operating history.

Our operations commenced in January 2004. Since our inception, we have incurred net losses. For the years ended December 31, 2006, 2005 and 2004, we incurred net losses of $8.7 million, $4.8 million and $1.9 million, respectively. The uncertainty and factors described throughout this section may impede our ability to economically find, develop and acquire natural gas and oil reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future.

Natural gas prices are volatile and a decline in prices could hurt our profitability, financial condition and ability to grow.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our gas properties depend heavily on the prices we receive from natural gas sales. Gas prices also affect our cash flows and borrowing base, as well as the amount and value of our gas reserves.

Historically, the markets for gas have been volatile and they are likely to continue to be volatile. Wide fluctuations in gas prices may result from relatively minor changes in the supply of and demand for gas, market uncertainty and other factors that are beyond our control, including:

- domestic supplies of natural gas;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- worldwide and domestic economic conditions;
- the level of consumer demand;
- the availability of transportation facilities;
- weather conditions; and
- governmental regulations and taxes.

These factors and the volatility of gas markets make it very difficult to predict future gas price movements with any certainty. Declines in gas prices would reduce our revenues and could also reduce the amount of gas that we can produce economically and therefore could have a material adverse effect on us.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions could change the character of our operations and business. The character of the new properties could be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

If we are not able to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find, develop and acquire oil and gas reserves that are economically recoverable. Our properties produce gas at a declining rate over time. In order to become profitable we must develop our recently acquired properties or locate and acquire new oil and gas reserves to replace those being depleted by production. We may do this even during periods of low oil and gas prices. Competition for the acquisition of producing oil and gas properties is intense and many of our competitors have financial and other resources for acquisitions that are substantially greater than those available to us. Therefore, we may not be able to acquire oil and gas properties that contain economically recoverable reserves, or we may not be able to acquire such properties at prices acceptable to us. Without successful drilling or acquisition activities, our reserves, production and revenues will decline.

Properties we acquire may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes an acquisition program. The successful acquisition of producing oil and gas properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, and may not permit us to become familiar enough with the properties to fully assess their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the environmental and production risks associated with the properties.

The guarantee of certain indebtedness of our subsidiary and the covenants in the agreements governing that debt and the guarantee could negatively impact our financial condition, results of operations and business prospects.

On December 28, 2006, we issued $15 million in Debentures to certain lenders. We guaranteed payment of this debt and pledged substantially all of our assets as collateral. If we fail to comply with the covenants and other restrictions in the agreements governing the Debentures, an event of default could occur that would permit the lenders to foreclose on substantially all of our assets. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. If we cannot make certain payments under the Debentures, we may not have sufficient funds to make the guaranteed payments. If we are required but unable to make the guaranteed payments under the Debentures out of cash on hand or from internal cash flow, we could attempt to refinance the Debentures, sell assets, or repay the Debentures with the proceeds from an equity or debt offering. However, we may not be able to raise sufficient capital through the sale of assets or issuance of equity or debt to pay or refinance the amounts owed. The terms of the Secured Guaranty and the Debentures may also prohibit us from taking such actions without first retiring the debt represented by the Debentures. Factors that will affect our ability to raise cash through a sale of assets or a debt or equity offering include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may, therefore, not be able to successfully complete any such offering or sale of assets.

The agreements governing the Debentures contain various covenants limiting the discretion of our management in operating our business.

The guarantee of, and the agreements governing, the Debentures contain various restrictive covenants. In particular, these agreements limit our ability, without lenders approval, to, among other things:

- pay dividends on, redeem or repurchase our capital stock;
- make loans to others;
- incur additional indebtedness or issue preferred stock;
- create certain liens; and
- purchase or sell assets.

If we fail to comply with the restrictions in the Secured Guaranty, or the agreements governing, the Debentures, an event of default may allow the creditors to foreclose on substantially all of our assets. Any such default or foreclosure could have a material adverse effect on us.

We may be required to make significant cash payments if we fail to satisfy certain registration requirements set forth in the Registration Rights Agreement.

In connection with the $15 million Debentures, we issued 1,250,000 shares of common stock to DKR Soundshore Oasis Holding Fund Ltd. and West Coast Opportunity Fund, LLC and entered into a Registration Rights Agreement. Pursuant to that agreement, if we fail to: (i) have the registration statement declared effective by the SEC on or before the date that is 150 days after December 28, 2006 (an Effectiveness Failure) or (ii) maintain the effectiveness of this registration statement while shares of common stock covered by the Registration Rights Agreement remain unsold (a Maintenance Failure), then, unless the grace periods set forth in the Registration Rights Agreement apply, as partial relief for the damages to any holder by any such delay in or reduction of its ability to sell the shares of common stock, we must pay to each holder an amount in cash equal to 1% of the aggregate purchase price (as such term is defined in the Securities Purchase Agreement for the Debentures) allocable to such holder s securities on each of the following dates: (i) the day of an Effectiveness Failure and on every 30th day thereafter until such Maintenance Failure is cured and (ii) the initial day of a Maintenance Failure and on every 30th day thereafter until such Maintenance Failure is cured. If we fail to make these registration delay payments in a timely manner, the registration delay payments will bear interest at the rate of 2% per month until paid in full. The aggregate amount of registration delay payments may not exceed $750,000. We filed the registration statement on Form S-3 with the SEC on February 2, 2007.

Our Senior Subordinated Convertible Notes (the Notes) are collateralized by some of our assets, which could result in a loss of those assets if we were to default on those debt instruments.

During the first quarter of 2006, we issued through a private offering approximately $22 million the Notes that carry an interest rate of 10% per annum, with interest due and payable on a quarterly basis. The Notes are collateralized by certain of our gathering assets. If we cannot make certain payments under the Notes, we may default upon our obligations and the noteholders under the Notes and our creditors could foreclose on these assets. Under certain circumstances, a default upon our obligations under the Notes could lead to an event of default under the Debentures. Any such default or foreclosure could have a material adverse effect on us.

Our development operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a disposition of properties and a decline in our natural gas reserves.

The energy industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with proceeds from the issuance of debt and equity plus cash generated by operations. We intend to finance our future capital expenditures with cash flow from operations and from debt or equity capital. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;

- the level of natural gas we are able to produce from existing wells;
- the prices at which natural gas is sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, then we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a possible disposition of properties and a decline in our reserves.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas will be found. The cost of drilling and completing wells is often uncertain, and oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental requirements;
- delays caused by regulatory approvals from state, local and other governmental authorities;
- shortages or delays in the availability of or increases in the cost of drilling rigs and the delivery of equipment;
- lack of availability of experienced drilling crews; and
- lack of pipeline availability or pipeline capacity.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies that we use do not allow us to know conclusively prior to drilling a well that oil or gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling costs.

Our future drilling activities may not be successful, or our overall drilling success rate or our drilling success rate for activity within a particular area may decline. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from them.

The occurrence of any or all of these risks could have a materially adverse effect on our business, financial condition and results of operations.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures.

Substantially all of our producing properties are located in the Rocky Mountain region, making us vulnerable to risks associated with operating in one major geographic area.

Our operations are focused on the Rocky Mountain region, which means our producing properties are geographically located in the states of Colorado, Nebraska and Wyoming. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these areas caused by significant governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation of natural gas produced from the wells in these basins.

Our operations are subject to operational hazards and unforeseen interruptions for which we may be inadequately insured, resulting in losses to us.

Our operations, including gathering, processing, exploitation and production, are subject to operational hazards and unforeseen interruptions such as natural disasters, adverse weather, accidents, fires, explosions, hazardous materials releases, mechanical failures and other events beyond our control. These events might result in a loss of equipment or life, injury or extensive property damage, as well as an interruption in our operations. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

A significant liability for which we were not fully insured could adversely affect us.

Our operations are subject to complex laws and regulations, including environmental regulations, that may result in substantial costs and other risks.

Federal, state and local authorities extensively regulate the energy industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of gas production. Noncompliance with statutes and regulations may lead to substantial penalties, and the overall regulatory burden on the industry increases the cost of doing business and, in turn, decreases profitability.

Governmental authorities regulate various aspects of gas drilling and production, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment and restoration.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities in jurisdictions where we are engaged in development or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We could face significant liabilities to governmental authorities and third parties for discharges of oil, natural gas or other pollutants into the air, soil or water, and we could have to spend substantial amounts on investigations, litigation and remediation. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, may have a material adverse effect on us.

Future oil and gas price declines or unsuccessful development efforts may result in write-downs of our development and production asset carrying values, thereby reducing our assets and net worth.

We follow the successful efforts method of accounting for our oil and gas properties. All property acquisition costs and costs of development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered.

The capitalized costs of our oil and gas properties, on a field basis, cannot exceed the estimated future net cash flows of that field. If net capitalized costs exceed future net revenues, we must write-down the costs of each such field to our estimate of fair market value. Unproved properties are evaluated at the lower of cost or fair market value. Accordingly, a significant decline in oil or gas prices or unsuccessful development efforts could cause a future write-down of capitalized costs, reducing our assets and net worth.

We review the carrying value of our properties quarterly based on prices in effect as of the end of each quarter. Once incurred, a write-down of oil and gas properties cannot be reversed at a later date even if oil or gas prices increase.

Competition in our industry is intense and many of our competitors have greater financial and technical resources than we do.

We face intense competition from major oil companies, independent oil and gas exploration and production companies, financial buyers and institutional and individual investors who are actively seeking oil and gas properties in the Rocky Mountain region in which we operate and elsewhere. Many of our competitors have financial and technical resources along with equipment, expertise, labor and materials significantly exceeding those available to us. In addition, many properties are sold in a competitive bidding process in which our competitors may be able to pay more for development prospects and productive properties, or in which our competitors have technological information or expertise to evaluate and successfully bid for the properties that is not available to us. Shortages of equipment, labor or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We, therefore, may not be successful in acquiring and developing profitable properties in the face of this competition.

A significant decrease in the supply of natural gas from our gas gathering customers could reduce our revenue and earnings.

Investments by our gas gathering customers in the maintenance of existing wells and the further development of their reserves will affect their production rates and the volume of gas we gather. Drilling activity generally decreases as gas prices decrease. We have no control over our customers level of drilling activity, the amount of reserves underlying their wells and the rate at which their production from a well will decline. Drilling activity of our customers is affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, geological considerations, governmental regulation and the availability and cost of capital. A significant decrease in the supply of natural gas we are gathering would reduce our revenue and results of operations.

We depend on our chief executive and chief operating officers for critical management decisions and industry contacts.

We do not have employment agreements with our chief executive and chief operating officers and do not carry key person insurance on their lives. The loss of the services of either of these executive officers, through incapacity or otherwise, could have a material adverse effect on our operations and would require us to seek and retain other qualified personnel.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Description of Properties

Powder River Basin - CBM

Gas produced from Powder River Basin coals is almost 100% methane. The gas is generated during the coal forming process and is trapped in the coal beds by water. In order to produce the coal gas, the formation must first be dewatered. As the water is removed from the coal, the gas is desorbed from the coal. All of the coal-bed reservoirs are low pressure and require compression in order for the gas to be delivered to a pipeline transportation system.

Natural gas wells in the Powder River Basin area typically experience sharp declines in production volume in the first several years of production. Production then stabilizes and declines more ratably over a gas well s average life of approximately eight to ten years. Other factors which influence the initial and long-term productivity of the coal-bed methane wells are the depths of the coal fields, the initial gas saturation levels of the coal field and the well spacing.

D-J Basin-Niobrara Formation

In 1972, Mountain Petroleum, Inc. completed five commercial Niobrara wells in Beecher Island Field. From 1975 to 1982 an additional 46 fields were discovered in Colorado, northwestern Kansas, and southwestern Nebraska. Recent activity in the area by Bill Barrett Corp., Berry Petroleum, Houston Exploration, Noble Energy, Petroleum Development Corp. and others have included amassing large acreage blocks, performing extensive seismic evaluations and initiating drilling programs.

Modern methods used to evaluate the Niobrara in the eastern D-J Basin are predominately driven by geophysics. Typically, leads are generated by 2-D seismic or subsurface mapping. The delineated anomalies are subsequently shot with 3-D seismic, effectively identifying gas by amplitude.

The Niobrara target zone in the eastern portion of the D-J Basin has a relatively low permeability. Production occurs in depths from 900 to 3,500 feet and the reservoir is somewhat under-pressured relative to normal hydrostatic pressure. Fields are generally located on low relief (50 to 200 feet) anticlines or faulted structures with the downdip portion of the reservoir generally wet. Completion techniques, as a standard practice, include hydraulically induced fractures.

Recluse Gathering Systems

In 2006, we made three acquisitions that have been combined into our Recluse Gathering System. The system now includes 2 compressor stations, interconnects with 2 major transportation lines and 74.5 miles of steel pipelines. We currently have contracts with two producers, with several other contracts in negotiation.

NESH Compressor Stations. We purchased these assets from Storm Cat on January 18, 2006. Assets include 2 compressor stations and 2 miles of 12-inch poly pipe connecting the stations on the low pressure side. The stations include piping, scrubbers, tanks, and compressor buildings. The compression lease, month to month, with Universal compression was assigned to us by seller. We signed a gathering agreement with Storm Cat at the same time.

High Pressure Discharge lines. We purchased these assets from Clear Creek Natural Gas, LLC on March 1, 2006. Assets include 4.5 miles of 8-inch steel pipe, 2 miles of 6-inch steel pipe, meter stations at both compressor stations, and an interconnect with Thundercreek, one of the major transportation lines in the area. We also acquired a fee-based gathering contract with Storm Cat for use of these facilities.

Maverick Pipelines. We purchased approximately 70 miles of 6-inch steel pipeline from Maverick Pipeline, LLC. Seven miles of this old oil gathering systems have been converted to gas service and we were assigned a gathering contract associated with this line. We also acquired an interconnect with Williston Basin Interstate Pipeline Company.

South Gillette (Formerly Known as Bear Paw) Gathering Systems

Effective August 1, 2004, we acquired certain gathering systems and related contracts from Bear Paw Energy (BPE) located in Campbell County, Wyoming. The systems acquired include the following:

- Gap gas gathering system;
- Bone Pile gas gathering system;
- Antelope Valley delivery line, and
- South Kitty delivery line.

Concurrent with the acquisition, we entered into an operations agreement with BPE. The agreement requires BPE to operate the systems for us, including repairs, maintenance and compression services, for a monthly fee of $80,000. As a result of the consolidation in the Bonepile area and a reduction in the compression utilized, this monthly fee was reduced to $58,000 in June,2006. The other significant factor impacting the South Gillette gathering system was our purchase of the underlying gas reserves from Pennaco in June 2006. This resulted in our owning approximately 50% of the gas being gathered. On January 24, 2007 JW Power purchased the compression from BPE and entered into a capital lease agreement with us. Concurrently we took over daily operations using our Gillette field employees.

The Gap and Bonepile gathering systems were constructed in 1999 and 2000, respectively. These systems consist of 8, 12, 16 and 20-inch steel pipe totaling 34 miles in length and 152 miles of low pressure poly pipe. Collectively, these systems are connected to approximately 650 CBM wells. The Antelope Valley and South Kitty Delivery lines were installed in 1999 and 2002, respectively. The Antelope Valley line is a 10-inch pipeline that moves gas from the Antelope Valley Facility to the Fort Union and Thunder Creek pipelines. The South Kitty line is a 12-inch pipeline that moves gas from the north side of the Bonepile gathering system to BPE South Kitty station.

Reserves

We engaged independent geological and petroleum engineering consultants Netherland, Sewell & Associates, Inc. (NSAI) in 2006, and Sproule Associates, Inc. (Sproule) in 2005, to estimate our natural gas reserves. We also review the calculations and assumptions these consultants use to calculate our reserves. We emphasize that reserve estimates are imprecise by their nature, and that reserve estimates on new discoveries and developments are less precise than reserve estimates for existing fields. Accordingly, we expect these estimates to change as time passes and information as to actual well performance can be included in those future estimates.

Proved oil and gas reserves are estimates of recoverable quantities of oil, natural gas and natural gas liquids that are determined using engineering and geological data with reasonable certainty. The reserve estimates are based on existing economic and operating conditions and include only existing wells from known reservoirs with existing equipment and technology. Our proved reserves are located in the Powder River Basin area of Wyoming and the D-J Basin in northeastern Colorado and southwestern Nebraska.

The following table summarizes our proved reserves data at December 31, 2006 and December 31, 2005, respectively:

	2006	**2005(2)**
Gas (MMcf) (1)	5,674	396
Standardized measure of discounted future net cash flows (in thousands)	$ 5,507	$ 688
Proved developed reserves (as % of total proved reserves)	32.3 %	100 %

(1) Million Cubic Feet (MMcf)

(2) These amounts represent proved developed producing reserves.

Due to a market price anomaly related to unseasonably warm weather and higher gas storage levels at the end of 2006, the gas price was substantially lower than the quarters before and after year-end 2006. The New York Mercantile Exchange (NYMEX) at year-end reflected a price of $5.64 per million British thermal units (MMBtu) or about 20% to 25% below the current gas futures contract prices. The CIG price of $4.46 per MMBtu was at a low point at year-end compared to the fourth quarter of 2006 and the first quarter of 2007.

Our year-end report of December 31, 2006 prepared by NSAI calculated estimated proved reserves and future revenues by using the weighted average price for total proved reserves of $3.39 per thousand cubic feet (Mcf) (or approximately $4.00 per MMBtu based on an 85% average conversion factor for these properties). The estimated reserves and future revenues would have presented a much different result if similar prices were in effect at year-end as were experienced during the quarters before and after year-end 2006, which ranged on average from $7.00 to $8.00 per MMBtu at Henry Hub and $4.50 to $6.50 per MMBtu from CIG, before regional differentials and transportation and compression charges.

Based on a more representative price range, using CIG prices as a reference, of $5.25 to $6.50 per MMBtu, the estimated increase in year-end future net revenues discounted at 10% would have been between 35% ($2.0 million) to 75% ($4.0 million) for proved reserves.

Gas Sales

The following table summarizes the volumes sold and realized prices from our properties during the years ended December 31, 2006 and December 31, 2005, respectively. *All items listed below are based on gas sales volume (Mcf). Therefore, these values are net numbers where fuel, lost and unaccounted for gas, and metering variances have been removed prior to the calculation.*

	2006	**2005**
Net annual gas sales (Mcf)(1)	396,000	6,000
Average net daily gas sales (Mcf)	1,085	85
Average realized price of gas per Mcf sold	$ 4.23	$ 8.50
Lease operating expense per Mcf sold	$ 3.20	$ 4.22
Production taxes per Mcf sold	$ 0.45	$ 1.06
Transportation expense per Mcf sold	$ 0.87	$ 0.38

(1) Net gas sales represent that portion of gas sold that is owned by us and produced to our ownership interest.

Productive Wells

As of December 31, 2006 and December 31, 2005, respectively we had working interests in 692 productive wells (571 wells net) and 10 productive wells (4 wells net). Productive wells are either producing or capable of producing although shut-in or de-watering. Gross wells represent the total number of wells in which we have a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by us. One or more completions in the same bore hole are counted as one well.

Drilling Activity

All of our drilling activity is performed by independent drilling contractors. The following table sets forth certain information regarding numbers of wells in our drilling activities for the periods indicated:

	2006 Gross	Net	2005 Gross	Net
Exploratory wells drilled:				
Productive	0	0	18	7
Development wells drilled:				
Productive	66	14.3	6	3
Total wells drilled:				
Productive	66	14.3	24	10

Gross wells represent wells in which we have a working interest; net wells represent our aggregate working interests in the gross wells.

Acreage

The following table details the gross and net acres of developed and undeveloped properties that we hold. Some of the developed and undeveloped acreage included herein has been earned as part of the Company s Farm-In and Development Agreement with Rocky Mountain Gas. As of December 31, 2006, our properties accounted for the following developed and undeveloped acres:

	Developed Gross	Net	Undeveloped Gross	Net	Total Gross	Net
Montana			5,893	2,357	5,893	2,357
Wyoming	29,010	28,292	301	162	29,311	28,454
Colorado	520	520	165,194	146,358	165,714	146,878
Nebraska			213,629	177,583	213,629	177,583
Total	29,530	28,812	385,017	326,460	414,547	355,272

Gross acres represent acres in which we have a working interest; net acres represent our aggregate working interests in the gross acres.

Office Facilities

We currently lease office space for our corporate headquarters in Denver, Colorado as well as office space for our Gillette, Wyoming field operations office.

ITEM 3. LEGAL PROCEEDINGS

Rocky Mountain Gas Agreement and Claims Dispute

On March 20, 2006, we terminated a Farmout and Development Agreement (the Farmout Agreement) dated August 1, 2005 with Enterra Energy Trust s wholly-owned subsidiary Rocky Mountain Gas, Inc. (RMG). We, however, continued as field operator under a Joint Operating Agreement (JOA) with RMG for certain CBM properties in Wyoming and Montana that are covered by the JOA. In February 2006, RMG executed 19 authorizations for expenditure to drill and complete the Moyer coal pilot wells. After termination of the Farmout Agreement, we, as operator under the JOA, issued a cash call to RMG for RMG s share of the estimated well costs for nine wells. In addition, after termination of the Farmout Agreement, RMG requested its full working interest in all wells drilled after the termination date.

We did not receive payment from RMG for the well costs as required under the JOA and issued a notice of default to RMG. The default was not cured within the period prescribed by the JOA and, under the JOA, RMG s interest was relinquished to us until such time as the proceeds from the 9 Moyer wells equal 300% of the capital expended by us on RMG s behalf.

On June 22, 2006, RMG filed an arbitration demand against us, asserting that the area of mutual interest provision in the terminated Farmout Agreement continues until August 2007 and, therefore, would provide RMG the right to participate in the Company s acquisition of certain oil and gas assets in Wyoming including those acquired from Pennaco. RMG also asserts that we should pay 100% of the costs of drilling the 9 Moyer wells for a 50% working interest. On August 22, 2006, we denied RMG s arbitration claims, and asserted counterclaims against RMG. On October 20, 2006, RMG amended its arbitration demand to add three additional claims. First, RMG claimed that the Company improperly failed to provide RMG with data regarding wells developed by the Company for the parties joint benefit. Second, RMG alleged that the Company improperly allocated, billed and failed to provide adequate documentation and support for amounts billed under the Farmout Agreement and Management Services Agreement. Third, RMG alleged that the Company improperly shut in one of RMG s natural gas wells and dug up its gathering line.

We also agreed upon termination of the Farmout Agreement to continue to provide management services until June 30, 2006. As of June 30, 2006, we had a receivable due from RMG of $386,000 for management services rendered and certain other amounts due from RMG. RMG disputed the amounts due to us. In July 2006, the Company and RMG entered into an interim agreement under which, among other things, RMG paid us $175,000 of the amount due at June 30, 2006. On October 24, 2006, RMG submitted its audit report to the Company in which RMG claimed that the Company improperly billed expenses to RMG under the terms of the agreements between the parties. RMG asserts that it is entitled to an amount in excess of $500,000 as a result of alleged improper charges by us under the Management Services Agreement (MSA) between the parties. We have also had an independent audit conducted which disputes the assertions contained in RMG s audit and concludes that RMG owes us at least $569,000, plus interest of $12,000, under the MSA. In February 2007, RMG paid $176,000 of this amount, leaving a balance due of $405,000 under the MSA. At December 31, 2006, we had a second receivable of $386,000 due from RMG for joint interest billings (JIB) on the operated wells, plus interest due of $8,000.

A collection reserve of $596,000 against the remaining JIB and MSA balances has been recorded at December 31, 2006. The balance sheet at December 31, 2006 includes these 2 RMG receivables of $405,000 for the MSA and $386,000 for JIB s totaling $791,000, less the allowance of $596,000, or $195,000. Any remaining disputed expenses will be presented for resolution at the May 2007 arbitration.

On January 11, 2007, we provided RMG with a Notice of Default for its failure to pay amounts due under the JOA totaling $324,779.69 plus interest. RMG did not cure the default by paying the amounts due within the 30-day cure period. On February 5, 2007 RMG provided us with a Notice of Default asserting that good cause exists to remove us as Operator for its alleged failure to perform its duties under the JOA as a prudent operator. We deny that we have failed to perform our duties, and deny that good cause exists to remove us as Operator. On February 6, 2007, RMG amended its arbitration demand to assert two additional claims in the pending arbitration. First, it added a claim based upon our alleged failure to perform its duties as a prudent operator. Second, it added a claim that asserts we owe RMG amounts to be determined at the arbitration for our use of RMG s Surface Facilities. On February 28, 2007 we held a mediation meeting with RMG with no resolution.

The arbitration is scheduled for May 2007. At this time, we cannot predict the outcome of the arbitration. However, management believes the outcome will not have a material adverse effect on the Company.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Principal Market and Price Range of Common Stock

Our common stock has traded on the American Stock Exchange (AMEX) since April 12, 2005 under the trading symbol PRB. The following table presents the reported high and low sales prices for each quarter since April 12, 2005:

	2006 Price Range High	**Low**	**2005 Price Range High**	**Low**
First Quarter	$ 6.67	$ 5.36	(1)	(1)
Second Quarter	$ 5.85	$ 4.01	$ 9.95	$ 6.21
Third Quarter	$ 5.50	$ 4.16	$ 10.32	$ 5.38
Fourth Quarter	$ 5.10	$ 2.91	$ 7.60	$ 5.41

(1) The 2005 amounts are blank for the first quarter as stock was not traded on AMEX until April 12, 2005.

	March 23, 2007	**December 31, 2006**	**December 31, 2005**
PRB s common stock closing price per share as reported on AMEX	$ 3.56	$ 3.33	$ 5.54

The number of holders of record of our common stock was 22 as of March 23, 2007.

This does not include holdings in street or nominee names. On March 23, 2007, the closing price of our common stock was $3.56 per share.

Performance Chart

This graph shall not be deemed filed for purposes of Section 18 of the Securities and Exchange Act of 1934 (the Exchange Act) or otherwise subject to the liabilities of that section nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933 or the Exchange Act, regardless of any general incorporation language in such filing.

Total returns assume $100 invested on April 12, 2005 in shares of PRB Energy, Inc., the AMEX Market Value (U.S.), and the AMEX Natural Resources, assuming reinvestment of dividends for each measurement period.

*** $100 invested on 4/12/05 in PRB stock or in index, including reinvestment of dividends.**

	April 12, 2005	**December 30, 2005**	**December 29, 2006**
PRB ENERGY, INC.	100.00	71.95	43.25
AMEX MARKET VALUE (U.S.)	100.00	110.24	127.89
AMEX NATURAL RESOURCES	100.00	139.49	160.02

Dividend Policy

We have never paid cash dividends on our common stock and we do not anticipate paying dividends in the foreseeable future. We expect that we will retain all available earnings generated by our operations for the development and growth of our business. In addition, under the terms of our Notes and Debentures that were issued in 2006, we are prohibited from declaring or paying cash dividends on our common stock during the period that any Notes or Debentures are outstanding and unpaid. Payment of any future dividends will be at the discretion of our Board of Directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, plans for expansion and the Note and Debenture agreements.

ITEM 6. SELECTED FINANCIAL DATA

The selected consolidated financial data for each of the three years in the period ended December 31, 2006 and the selected consolidated balance sheet data as of December 31, 2006, 2005 and 2004 are derived from, and qualified by reference to, our audited consolidated financial statements in Item 8 of this report. The selected financial data for each of the periods presented ending December 31, 2003 and 2002 and the selected balance sheet data as of December 31, 2003 and 2002 are derived from audited financial statements of TOP, our predecessor company, as referenced in our 2005 form 10-K.

The following financial data should be read in conjunction with, and are qualified by reference to, our consolidated financial statements and related notes thereto in Item 8 of this report and Management s Discussion and Analysis of Financial Condition and Results of Operations included in Item 7 of this report.

	PRB Energy, Inc.			TOP Gathering, LLC (Predecessor)	
	2006	**2005**	**2004**	**2003**	**2002**
(in thousands, except per share amounts and unaudited operating data)					
Audited Financial Information					
Statement of Operations Data:					
Revenue - E&P	$ 1,676	$ 51	$	$	$
Revenue - G&P	2,612	2,834	2,532	1,999	2,097
Management and other revenue	547	270			
Operating costs - E&P	1,266	17			
Operating costs - G&P	2,469	1,755	1,314	1,900	2,725
Production taxes and other deductions - E&P	522	17			
General and administrative expenses	5,026	2,029	1,184	*	*
Depreciation, depletion & amortization					
DD&A - E&P	764	98			
DD&A - G&P	972	944	656	*	*
Net (loss) income (1)	(8,659)	(4,829)	(1,863)	79	(636)
Net loss per share - basic and diluted	$ (1.16)	$ (0.69)	$ (1.33)	$ *	$ *
Balance Sheet Data:					
Oil and gas properties, net	$ 19,746	$ 1,531	$	$	$
Gathering assets, net	6,912	5,856	8,098	618	1,125
Total assets	49,843	17,440	11,399	1,603	1,899
Long-term liabilities	35,786	434	65	86	260
Shareholders equity	$ 11,224	$ 15,257	$ 9,318	$ 820	$ 1,241
Operating Data:					
Cash flow (used in) provided by operations	$ (4,356)	$ (781)	$ 72	$ 655	$ (414)
Exploitation and development of natural gas properties	(5,184)	(1,058)			
Property/facility acquisitions	(17,453)	(336)	(10,606)	(14)	(1,150)
Additions to other fixed assets	$ (86)	$ (921)	$ (41)	$ *	$ *
Unaudited Operating Data (2)					
Natural gas operations (per Mcf):					
Average sales price	$ 4.23	$ 8.50	$	$	$
Average operating cost	3.20	4.22			
Average production cost	1.32	1.44			
Average DD&A	$ 1.93	$ 16.33	$	$	$
Sales (Mcf)	396,000	6,000			

* denotes information from TOP that is not available in these selected financial data categories.

Note (1): The net loss in 2006 includes a non-cash impairment charge of $790,000 ($.10 per basic and diluted share). The net loss in 2005 includes a non-cash impairment charge of $2.5 million ($.36 per basic and diluted share) and $76,000 for cumulative effect of change in accounting principle ($.01 per basic and diluted share). For additional information on these items see Note 5 Property, Equipment and Contracts and Note 7 Asset Retirement Obligations to our consolidated financial statements in Item 8 of this report.

Note (2): All items listed under this category are based on gas sales volume (Mcf). Therefore, these values are net numbers where fuel, lost and unaccounted for gas and metering variances have been removed prior to the calculation.

17

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

We were originally organized as a mid-stream energy company providing gathering and processing services to CBM gas producers. During 2005 and 2006, we expanded our operations to include developing and producing natural gas properties and providing management services as contract operator. These activities are in addition to our gas gathering and processing segment. The strategies to accomplish our goal of reaching positive cash flow and increasing shareholder value include:

- Growth in natural gas production and natural gas reserves in the Powder River Basin, the D-J Basin and other basins in the continental United States

- Strategic growth of gas gathering and processing systems for ourselves and for third parties

- Continued asset value growth through identification of undervalued assets which the company believes hold significant upside potential

Notable Items in 2006

- Completed Pennaco acquisition which provides the development acreage for the Moyer-coal development program

- Acquired 385,000 acres in the D-J Basin from Anadarko which included the acreage, producing reserves, a gathering system and 3D and 2D seismic data

- Generated positive cash flow from G&P assets

- Acquired gathering systems in the Recluse, Wyoming area

- Issued Notes raising approximately $22 million

- Issued Debentures raising approximately $15 million

Expectations for 2007

- Generate positive cash flow from E&P operations

- Initiate drilling potential locations in the Niobrara formation in the D-J Basin

- Initiate drilling program to develop the Moyer-coal in the Powder River Basin

- Locate and complete one or more significant acquisitions

- Expand our customer base and cash flow from G&P operations

Results of Operations

The following financial data should be read in conjunction with, and are qualified by reference to, our consolidated financial statements and related notes thereto in Item 8 of this report.

Overview

Factors affecting comparability In 2006, as the result of our entry into E&P operations with the completion of two substantial acquisitions and related financing, our comparability of 2006 to prior years revenues and expenses is markedly different. The 2006 E&P results reflect changes that are several fold increases over prior years due to our expanded E&P operations.

Revenue Our operations in 2006 were focused on developing the E&P segment of the business. Our revenues for E&P have substantially increased several fold in 2006 primarily due to the start-up of our E&P operations with the June 30, 2006 acquisition of CBM properties from Pennaco in the Powder River Basin of Wyoming. Our revenues for E&P of $1.7 million are determined by production from our existing properties and price based on market conditions for trading natural gas product. These market conditions such as weather, pipeline capacity and natural gas storage may have substantial effect on the revenues generated by our E&P segment.

Our gas gathering fees are based on contractual rates with our customers and will vary with system throughput as well as the level of services provided and customer mix. These fees are not currently regulated by any governmental authority.

Our management services fees were determined in accordance with our MSA with RMG and varied depending on the amount of support services that were required to fulfill our obligations under this contract determined on a cost plus 15% basis. On June 30, 2006, we terminated the MSA.

Our natural gas revenue will vary based on the price of natural gas and the quantities and quality of the gas we deliver.

E&P Operating Expense E&P operating expense includes costs associated with operating the natural gas properties. Such costs include labor related to pumper and direct field supervision, electricity, surface-use agreements, equipment rental, fuel, chemicals, road maintenance, permits, supplies and other relevant well costs incurred to extract the natural gas from the well.

G&P Operating Expense Gas gathering expense includes compression, site supervision costs, maintenance and operating supplies, property taxes, insurance, land use and surface rights payments and contract services, all of which are relatively fixed costs. Operating expenses also include transportation fees paid to others which vary with the throughput on our gathering lines.

E&P Production Taxes and Other E&P production costs include production taxes and deductions necessary to bring the natural gas product to market. Production taxes are determined by the taxing authority. In 2006, our production taxes were paid primarily to Wyoming including, ad valorem charged by the county based on assessed valuation of the properties and severance and conservation tax charged by the state. A nominal amount was paid to Colorado in connection with our acquisition of the Niobrara formation properties which closed on December 28, 2006.

Depreciation, Depletion, Amortization and Accretion Expense Depreciation expense relates to our compressor sites, pipelines and other gas gathering equipment, office furniture, office equipment and computers. Depletion expense relates to developed and undeveloped leaseholds, capitalized development costs and related equipment. Amortization expense relates to the customer contracts underlying the gas gathering systems. Accretion expense relates to the change in our asset retirement obligation liability due to the passage of time. Depreciation and amortization expense are based on estimates of the related assets useful lives. Depletion expense is calculated using the unit-of-production method based on estimated proved or estimated proved developed reserves. Accretion expense is calculated using the effective interest method.

General and Administrative Expense General and administrative expense includes the costs associated with our corporate office, including personnel costs, professional fees, office rent and other office support costs. It also includes bad debt expense related to our 2006 allowance of approximately $596,000 for collection of certain RMG receivables discussed under LEGAL PROCEEDINGS in Item 3 of this report as well as Note 3 Concentration of Credit Risk to our consolidated financial statements in Item 8 of this report.

Interest Expense During 2005, we had a note payable to the Bank of Oklahoma under a line of credit in the amount of $1.5 million, secured by our gas gathering assets and incurred interest of $49,000. Following the payment of the bank line of credit in full in April 2005, the bank released their security interest in the gathering assets and the $1.0 million certificate of deposit pledged by a preferred stockholder.

During the first quarter of 2006, we issued approximately $22 million of Notes and incurred interest of $2 million for the year. On December 28, 2006, we issued $15 million of Debentures and incurred interest of $16,000 through year-end.

Asset Impairment Charge Assets are evaluated for impairment periodically throughout the year. In 2005 the company had an impairment charge for its TOP gathering asset. In 2006, we had an impairment charge for E&P properties in the Reno/Dilts field of the Powder River Basin. More discussion of impairment charges is in the Critical Accounting Policies and Estimates of Item 7 of this report.

Exploration Expense Exploration expense includes the costs of drilling unsuccessful exploratory wells. See the description of exploration expense in the Critical Accounting Policies and Estimates of Item 7 of this report.

2006 Compared to 2005

Revenue increased $1.7 million, or 53%, in 2006 primarily due to the increase of $1.6 million in E&P gas sales, the majority resulting from revenues generated from the new Pennaco assets beginning in July 2006. Revenue from management fees also increased by $277,000. These revenue increases offset a $222,000 decrease in G&P revenue in 2006 as a result of inter-company eliminations of revenues that were previously Pennaco third-party recognized revenues. Pennaco represented 34% of our 2005 total revenues compared to only 13% of 2006 total revenues.

Selected Operating Expenses. The following table and the explanations that follow present information about our operating expenses for each of the years ended December 31, 2006 and 2005:

(in thousands)	**2006**	**2005**	**Increase (Decrease)**	**Change**
Operating costs - E&P	$ 1,266	$ 17	$ 1,249	*
Operating costs - G&P	$ 2,469	$ 1,755	$ 714	41 %
Production taxes and other deductions - E&P	$ 522	$ 17	$ 505	*
Depreciation, depletion and amortization - E&P	$ 764	$ 98	$ 666	*
Depreciation, depletion and amortization - G&P	$ 972	$ 944	$ 28	3 %
General and administrative	$ 5,026	$ 2,029	$ 2,997	148 %
Interest expense	$ 2,287	$ 49	$ 2,238	*

* Percentages greater than 200% and comparisons from positive to negative values are not shown.

As we remain in a strong commodity price environment, we anticipate that cost pressures within our industry may continue due to greater field activity and rising service costs in general. Based on current plans, we are targeting the reduction of costs, principally electricity, third party services, compression expense, surface rentals and other field expenses. The changes as explained in the preceding table were primarily related to the following items:

- E&P operating costs: 2006 was our first full year of E&P operations. Our acquisition from Pennaco in the Powder River Basin resulted in higher production costs as we took over the operations in that area, increased our operating personnel, and brought on shut-in properties to ramp up production in the area.

- G&P operating costs: Our operating costs increased as a result of the acquisition of the Recluse gathering system.

- E&P Production taxes and other deductions: As a result of acquiring the Pennaco properties, we saw an increase in our revenues that directly relates to our production taxes and other deductions.

- Depreciation, depletion and amortization: Increases for E&P resulted from the additions of properties during the year as we developed our upstream energy business. The increased depreciation, depletion and amortization for G&P assets in 2006 resulted from the acquisition of the Recluse Gathering Systems which is further discussed in Item 1, Business - Acquisitions and Divestitures of this report.

- General and administrative: Our increase was a result of adding to our corporate office support staff, E&P operations management and staff and overall growth through acquisitions during 2006. We anticipate these costs will stabilize during 2007 with potential increases in legal and third party consulting expenses from future operations and acquisitions activity.

- Interest expense: Interest expense increased substantially in 2006 over 2005 as a result of the financing activities to grow our business during 2006. In the first quarter of 2006, we issued Notes to facilitate financing needs for future acquisitions. The majority of the interest expense increase was a result of interest incurred on these Notes. In addition, on December 28, 2006, in connection with the acquisition of properties in the D-J Basin, we issued Debentures. We expect the interest expense to increase in 2007 as a result of the added debt. See Note 10 Borrowings to our consolidated financial statements in Item 8 of this report for additional disclosures related to these financing facilities.

2005 Compared to 2004

Revenue increased $623,000, or 25%, in 2005 over 2004 primarily due to an acquisition-timing related increase of $1.1 million in gas gathering revenue applicable to our BPE systems which we acquired in August 2004. Revenue from management fees and natural gas sales, activities that were initiated during the year ended December 31, 2005, also increased by $270,000 and $51,000, respectively. These revenue increases offset a $753,000 decrease in gas gathering revenues in 2005 from our TOP system resulting from a decline in volumes and the loss of a customer. This customer represented 11% of our 2004 revenues. We divested our assets relating to our TOP gathering system in 2006.

Selected Operating Expenses. The following table and the explanations that follow present information about our operating expenses for each of the years ended December 31, 2005 and 2004:

(in thousands)	2005	2004	Increase (Decrease)	Change
Operating costs - E&P	$ 17	$	$ 17	100 %
Operating csots - G&P	$ 1,755	$ 1,314	$ 441	34 %
Production taxes and other deduction - E&P	$ 17	$	$ 17	100 %
Asset impairment charge	$ 2,487	$	$ 2,487	100 %
Exploration expense	$ 450	$	$ 450	100 %
Depreciation, depletion and amortization	$ 1,067	$ 656	$ 411	63 %
General and administrative	$ 2,029	$ 1,184	$ 845	71 %

- G&P operating costs: Costs increased $441,000 or 34% mainly due to the $721,000 increase in BPE systems operating costs resulting from the timing of the acquisition of this system. These costs offset a decrease in gas gathering expenses relating to our TOP system as a result of releasing excess compression capacity.

- E&P Production taxes and other deductions: We incurred gas production costs for the first time in 2005 as a result of our entry into E&P activities.

- Asset Impairment Charge: In 2005, we recorded an asset impairment charge of $2.5 million related to our TOP gas gathering system. As a result of declining volumes and the loss of a customer, we performed an evaluation of the recoverability of our carrying value of this system using undiscounted cash flow projections. We determined that the estimated fair value of these gathering system assets was less than our carrying value. The estimated fair value was determined using discounted values of probability weighted expected cash inflows and an independent appraiser s valuation of our TOP gas gathering system. We also evaluated our BPE gas gathering system for recoverability of carrying values and determined that no impairment was warranted at December 31, 2005. See also Note 5 Property, Equipment and Contracts to our consolidated financial statements in Item 8 of this report.

- Exploration Expense: We incurred $450,000 of expense in 2005 relating to the drilling costs of 6 unsuccessful wells. Four of these six wells were lost due to mechanical failure and have been subsequently re-drilled.

- Depreciation, depletion and amortization: Depreciation, depletion, amortization and accretion expense increased $411,000 or 63% over 2004 primarily due to $491,000 of additional depreciation and amortization expense applicable to the BPE assets which were acquired in August 2004. This increase was offset by lower TOP system depreciation and amortization as a result of the TOP impairment.

- General and administrative: Expenses in 2005 increased $845,000 or 71% over 2004 mainly due to increases of $381,000 in professional fees, $166,000 in additional expenses associated with being a public company and $134,000 in increased payroll costs. Professional fees increased due to additional legal, accounting and engineering activities associated with our entering the E&P business and expanding our G&P business. All other general and administrative expense increased $164,000 net, during 2005 as compared to 2004.

Estimated 2007 Selected Operating Expenses

(in thousands)	2007 Anticipated Range Low	High
Operating costs - E&P	$ 2,560	$ 3,464

Operating costs - G&P	$	2,932	$	3,967
Production taxes and other deductions - E&P	$	2,563	$	3,469
DD&A - E&P	$	3,379	$	4,572
DD&A - G&P	$	1,448	$	1,959
General and administrative	$	4,365	$	5,905
Interest expense	$	3,506	$	4,744

The above table represents a range for our expectations in 2007 for selected financial data.

Critical Accounting Policies and Estimates

Please refer to Note 2 Summary of Significant Accounting Policies to our consolidated financial statements in Item 8 of this report. In the Summary of Significant Accounting Policies we highlight critical accounting policies and estimates relevant to our consolidated financial statements and projections. Below are highlights related to accounting policies and estimates affecting our operations.

Allowance for RMG receivable In 2006, we estimated an allowance for doubtful accounts of $596,000 pertaining to RMG. RMG s receivables totaled $791,000 at December 31, 2006 and the remaining balance, after the allowance, is reflected in the consolidated financial statements as $195,000. The estimate is based on the amount which is considered doubtful as to collection based upon legal proceedings that began in 2006 and are continuing into 2007. Refer to Item 3, Legal Proceedings, for additional details regarding the RMG Agreement and Claims Dispute.

Asset impairment Reflected on our December 31, 2006 statement of operations is $790,000 of impairment charge that represents the remaining net book value of the Reno/Dilts wells previously included in E&P property assets and located in the Powder River Basin. In September 2005, pursuant to the farmout agreement with RMG, we drilled CBM wells in the Reno/Dilts area in order to develop the property. The target production level was 700 to 800 Mcf/day. Over the remainder of 2005 and 2006, the gas production increased to 300 Mcf/day and leveled off. This project required us to purchase diesel fuel to run the generators and down hole pumps. With the production leveling off, management determined that there was insufficient revenue projected to cover the operating expenses of the rental generators and the diesel. These uneconomical properties were subsequently shut in during the first quarter of 2007.

For the year ended 2005, $2.5 million was charged off to expense related to the TOP gathering system, including $1.6 million for property and equipment and $842,000 for contracts.

Exploration Costs We incurred exploration costs of $50,000, $450,000 and $0 in 2006, 2005 and 2004, respectively. For 2007, expected costs consist primarily of geological and geophysical costs. We purchased 3-D seismic surveys in the acquisition of the D-J Basin acreage. We are projecting total costs in 2007 of between $4 million and $8 million for the development of probable and possible reserves in both the Powder River Basin and the D-J Basin. Management believes it is more likely than not that most of these costs will ultimately be capitalized as development assets due to the 3-D seismic success rate by other operators in drilling in the D-J Basin.

Income Taxes From inception through December 31, 2006, we generated projected, estimated net operating losses on a tax basis of approximately $16 million versus $4.6 million at December 31, 2005. As of December 31, 2006 we had an estimated tax asset of $2.7 million, which has been fully reserved with a valuation allowance, and thus no tax benefit credit was reported for 2006. We have incurred start-up expenses and taxable deductions through drilling activities to date, which combined with the tax loss carryforwards, will offset taxable income from operations for the foreseeable future. We continue to evaluate the reasonableness and appropriateness of the valuation allowance in future periods.

Asset dispositions TOP Gathering System customers were notified on March 21, 2006 that the TOP system rates would be increased to cover its cash costs plus 15% for a two-month period. The buyer of our TOP system exercised their right as a customer to purchase the TOP System during the third quarter of 2006, resulting in a gain of $309,000 reflected as other income in our statement of operations. We have significantly increased and strengthened our portfolio of assets since 2005 and expect to continue to make acquisitions. We do not anticipate significant divestitures in 2007. There are no gas properties and equipment classified as held for sale at December 31, 2006 in accordance with SFAS No. 144.

Estimated oil and gas reserve quantities Proved oil and gas reserves are estimates of recoverable quantities of oil, natural gas and natural gas liquids that are determined using engineering and geological data with reasonable certainty. Reserve estimates are prepared by independent petroleum engineers. The reserve estimates are based on existing economic and operating conditions and include only existing wells from known reservoirs with existing equipment and technology. All of the proved reserves in 2005 were located in the Powder River Basin area of Wyoming. In 2006 we added proved and unproved reserves in the Denver-Julesburg (D-J) Basin of northeastern Colorado and southwestern Nebraska. See also Note 13 Disclosures about Oil and Gas Producing Activities to our consolidated financial statements in Item 8 of this report for more information on reserve estimates.

Financial Condition, Liquidity and Capital Resources

Substantial capital is required to replace and grow reserves. We achieve reserve replacement and growth primarily through successful development drilling and the acquisition of properties. Fluctuations in commodity prices and pipeline capacity have been the primary reason for short-term changes in our cash flow from operating activities. We expect the net long-term growth in our cash flow from operating activities will be the result of growth in production as affected by period to period fluctuations in commodity prices. In 2006, we financed our growth by a combination of utilization of working capital and issuance of debt securities.

Capital Expenditures We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. Acquisitions made in 2006 have been financed through our Notes and Debentures. We intend to utilize working capital as well as seek a bank credit facility in 2007 to continue to finance future capital expenditures. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes. Excess cash generated from operations is expected to be applied toward acquisitions, debt reduction or other corporate purposes.

In 2007, we have a capital program for both E&P and G&P, pending additional financing, of approximately $25 million. We intend to pay for this development utilizing current working capital, establishing a bank credit facility and, possibly, raising debt or equity capital during 2007. Upon commercial production we will proceed with further development of the deeper Moyer coal zones underlying the properties acquired from Pennaco. We plan to spend 90% of our capital expenditures for E&P operations. This could be revised due to lower commodity price expectations, timing of deliveries out of the Powder River basin, equipment availability, permitting or other factors. The 2007 capital budget is focused primarily on converting probable and possible reserves as well as developing existing reserves in the Powder River Basin and D-J Basin.

Working Capital and Cash Flows Cash flow from operations is dependent upon the price of natural gas and our ability to increase production, and manage costs. Natural gas prices decreased in 2006 compared to 2005 and we increased production as a result of our recent acquisitions and development program.

Our working capital balance has increased in 2006 over 2005 as a result of the issuance of the Notes during the first quarter of 2006 in connection with the acquisition of interest in the Powder River Basin as well as the Debentures during December 2006 in connection with the acquisition of interest in the Niobrara field located in Northeastern Colorado and Nebraska. For more in depth discussion of this financing please reference Note 10 Borrowings and Note 4 Acquisitions to the consolidated financial statements in Item 8 as well as 2006 Acquisitions and Divestitures in Item 1 of this report.

The table below compares financial condition, liquidity and capital resource changes as of and for the years ended December 31:

(in thousands, except for production and average prices)	2006	2005	Change
Average gas sold (Mcf/D) (1)	1,085	16	*
Average gas sales prices, per Mcf (1)	$ 4.23	$ 8.50	(50.2)%
Net cash used by operating activities	$ 4,356	$ 781	*
Working capital	$ 11,640	$ 7,004	66.2 %
Sales of natural gas	$ 1,676	$ 51	*
Gas gathering revenue	$ 2,612	$ 2,834	(7.8)%
Long-term debt	$ 36,972	$ 17	*
Capital expenditures, including acquisitions	$ 22,723	$ 2,315	*

*Percentages greater than 200% and comparisons from positive to negative values are not shown.

Note (1) All items listed under natural gas operations are based on gas sales volume per Mcf, or gas volumes sold per day (Mcf/D). Therefore, these values are net volumes where fuel, lost and unaccounted for gas, and metering variances have been removed prior to the calculation.

Due to a market price anomaly related to unseasonably warm weather and higher gas storage levels at the end of 2006, the gas price was substantially lower than the quarters before and after year-end 2006. The New York Mercantile Exchange (NYMEX) at year-end reflected a price of $5.64 per million British thermal units (MMBtu) or about 20% to 25% below the current gas futures contract prices. The CIG price of $4.46 per MMBtu was at a low point at year-end compared to the fourth quarter of 2006 and the first quarter of 2007.

Our year-end report of December 31, 2006 prepared by NSAI calculated estimated proved reserves and future revenues by using the weighted average price of total proved reserves of $3.39 per thousand cubic feet (Mcf) (or approximately $4.00 per MMBtu based on an 85% average conversion factor for these properties). The estimated reserves and future revenues would have presented a much different result if similar prices were in effect at year-end as were experienced during the quarters before and after year-end 2006, which ranged on average from $7.00 to $8.00 per MMBtu at Henry Hub and $4.50 to $6.50 per MMBtu from CIG, before regional differentials and transportation and compression charges.

Based on a more representative price range, using CIG prices as a reference, of $5.25 to $6.50 per MMBtu, the estimated increase in year-end future net revenues discounted at 10% would have been between 35% ($2.0 million) to 75% ($4.0 million) for proved reserves.

Credit Facility We have had recent discussions with some banks and we anticipate obtaining a bank credit facility during 2007. The primary sources of financing to date have been through private placements of debt securities. In 2007, we have sufficient capital to meet capital requirements for the first nine months of this year and plan to establish a bank credit line later in the year as reserves grow. There is no guarantee that we will be able to obtain a bank credit facility on terms acceptable to us.

22

Contractual Obligations

The following table summarizes our future commitments as of December 31, 2006 (in thousands):

	2007	2008	2009	2010	2011	Thereafter	TOTAL
Long-term debt obligations	$ 4,176	$ 39,729	$	$	$	$	$ 43,905
Operating leases	674	666	644	667	501	2,024	5,176
Total commitments	$ 4,850	$ 40,395	$ 644	$ 667	$ 501	$ 2,024	$ 49,081

The above table does not include asset retirement obligations, accounts payable or other accrued liabilities recorded on our consolidated balance sheet as of December 31, 2006. Asset retirement obligations are not included as we cannot determine with accuracy the timing of such payments. The table does not include any commitments entered into after December 31, 2006. Refer to Note 17 Subsequent Events to our consolidated financial statements included in Item 8 of this report.

We have acquired gas gathering properties and contracts that include operating leases in respect to surface-use rights that are cancelable in the event that gas gathering activities cease as a result of declining production. We also have purchased commitments for future field operations and maintenance activities with third party providers. In addition, we are a party to non-cancelable operating leases for office space, office equipment and other items required for operations. The table above includes estimated future purchase commitments relating to these operations support contracts. With regard to the operating leases, future minimum lease payments are calculated based on the contractual rate and period, or if the contract was a surface-use agreement, future minimum lease payments were calculated based on the estimated lives of the associated gas reserves (through 2014) and the applicable contract rate.

There is a default provision in the Debentures maturing on August 31, 2008 please refer to Note 10 Borrowings to our consolidated financial statements in Item 8 of this report for more information on our senior Debentures.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to certain market risks inherent within the energy industry including natural gas price volatility and pipeline capacity. We intend to manage our operations in a manner designed to minimize our exposure to such market risks. Since our gas volumes produced during 2005 and 2006 were at start-up levels, we did not have the quantity of product to consider it beneficial to institute a hedging policy to date.

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. We assess the financial strength of our customers through regular credit reviews in order to minimize the risk of non-payment.

Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. Because we sell natural gas at spot prices our financial results will be affected by changes in the price of natural gas. The estimated reserves and future revenues would have presented a much different result if similar prices were in effect at year-end as were experienced during the quarters before and after year-end 2006, which ranged on average from $7.00 to $8.00 per MMBtu at Henry Hub and $4.50 to $6.50 per MMBtu from CIG, before regional differentials and transportation and compression charges.

Interest Rate Risk

Interest rate risk will exist with respect to new debt offerings that bear interest at floating rates. At December 31, 2006 we had no bank indebtedness. Refer to Note 10 Borrowings to our consolidated financial statements included in Item 8 of this report with respect to our debt offering of the Notes and Debentures.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements required pursuant to this item are included in Item 15 of this Annual Report on Form 10-K and begin on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

We maintain disclosure controls and procedures as defined in Rules 13 a 15 (e) and 15 d 15 (e) of the Securities Exchange Act of 1934 designed to provide reasonable assurance that information required to be disclosed in our reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Principal Financial Officer, to allow timely decisions regarding required disclosure. Significant improvements were achieved by the end of the fourth quarter of 2006 in satisfactorily instituting all of the procedures outlined in our last report to fully remediate the previously reported deficiencies. Our management, with the participation and oversight of our Chief Executive Officer and Principal Financial Officer, evaluated these changes in design and effectiveness of our disclosure controls and procedures as of December 31, 2006. On the basis of these findings, our Chief Executive Officer and our Principal Financial Officer have concluded that our disclosure controls and procedures were effective, as of December 31, 2006.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The required information for this item is incorporated by reference to our Proxy Statement for the 2007 Annual Meeting of Stockholders. The Proxy Statement will be filed with the SEC not later than 120 days after the end of our fiscal year.

Our Board of Directors has adopted a Code of Business Conduct & Ethics, included as Exhibit 14.1 to this annual report on Form 10-K, that applies to our Directors, executives, officers and employees. Our Code of Business Conduct & Ethics can be found on our website, which is located at www.prbenergy.com. We intend to make all required disclosures concerning any amendments to, or waivers from, our Code of Business Conduct & Ethics on our website. Any person may request a copy of the Code of Ethics, at no cost, by writing to us at the following address: PRB Energy, Inc., 1875 Lawrence Street, Suite 450, Denver, Colorado 80202, attention: Corporate Secretary.

ITEM 11. EXECUTIVE COMPENSATION

The required information for this item is incorporated by reference to our Proxy Statement for the 2007 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The required information for this item is incorporated by reference to our Proxy Statement for the 2007 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The required information for this item is incorporated by reference to our Proxy Statement for the 2007 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The required information for this item is incorporated by reference to our Proxy Statement for the 2007 Annual Meeting of Stockholders. The Proxy Statement will be filed with the Securities and Exchange Commission not later than 120 days after the end of our fiscal year.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

15(a)(1) Consolidated Financial Statements

The following consolidated financial statements are filed as part of this report:

15(a)(2) Financial Statement Schedules

Schedules are omitted because they are not required or because the information is provided elsewhere in the consolidated financial statements.

24

15(a)(3) Exhibits

Exhibit Number	**Description**
(3.1)	Amended Articles of Incorporation of the Registrant (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
3.2	Amendment to the Articles of Incorporation to change the Company s name
(3.3)	Amended By-laws of the Registrant (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(4.5)	Form of Common Stock Certificate (filed as an exhibit to Form 8-A filed on April 8, 2005).
(4.6)	Form of Senior Subordinated Convertible Note (filed as an exhibit to Form 10-K filed on April 14, 2006 and incorporated by reference herein).
(4.7)	Form of Registration Rights Agreement between the Company and the holders of the Company s Senior Subordinated Convertible Notes (filed as an exhibit to Form 10-K filed on April 14, 2006 and incorporated by reference herein).
(4.8)	Form of Senior Secured Debentures (filed as an exhibit to Form 8-K filed on January 5, 2007 and incorporated by reference herein)
(4.9)	Pledge and Security Agreement, dated as of December 28, 2006, by and among PRB Energy, Inc., PRB Oil & Gas, Inc., PRB Gathering, Inc., and the Secured Parties named therein (filed as an exhibit to Form 8-K filed on January 5, 2007 and incorporated by reference herein)
(4.10)	Secured Guaranty, dated as of December 28, 2006, made by PRB Energy, Inc. and PRB Gathering, Inc. (filed as an exhibit to Form 8-K filed on January 5, 2007 and incorporated by reference herein)
(4.11)	Registration Rights Agreement, dated as of December 28, 2006, by and among PRB Energy, Inc. and the Buyers named therein (filed as an exhibit to Form 8-K filed on January 5, 2007 and incorporated by reference herein)
(10.1)*	Equity Compensation Plan Filed (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(10.2)	Form of Amended and Restated Warrant Certificate (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.4)	Bear Paw Energy, LLC Purchase and Sale Agreement (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(10.5)	Bear Paw Energy, LLC Mortgage, Security Agreement, Assignment of Proceeds, and Financing Statement (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(10.6)	Bear Paw Energy, LLC Promissory Note (filed as an exhibit to Form S-1/A filed on January 28, 2005 and incorporated by reference herein).
(10.7)	Bear Paw Energy, LLC Operations Agreement (filed as an exhibit to Form S-1 filed on November 1, 2004 and incorporated by reference herein).
(10.8)	Bank of Oklahoma Promissory Note (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.9)	Bank of Oklahoma Mortgage and Security Agreement (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.10)	Gathering Services Agreement United Energy Trading, LLC (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.11)	Gathering Services Agreement Pennaco Energy Inc. (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.12)	Gathering Services Agreement Natural Gas Fuel Company, Inc. (filed as an exhibit to Form S-1/A filed on March 1, 2005 and incorporated by reference herein).
(10.13)	Farmout and Development Agreement dated August 1, 2005 between Rocky Mountain Gas, Inc. and PRB Energy, Inc. (filed as an exhibit to Form 8-K filed on September 9, 2005).
(10.14)	Management Services Agreement dated August 1, 2005 between Rocky Mountain Gas Inc., Enterra Energy Trust and PRB Energy, Inc. (filed as an exhibit to Form 8-K filed on September 9, 2005).
(10.15)	Form of Subscription Agreement between the Company and the subscribers to the Company s Senior Subordinated Convertible Notes (filed as an exhibit to Form 10-K filed on April 14, 2006 and incorporated by reference herein).
(10.16)	Gathering Services Agreement - Storm Cat Energy (USA) Operating Corporation (filed as an exhibit to Form 8-K filed January 27, 2006 and incorporated by reference herein)
(10.17)	Purchase and Sale Agreement between Pennaco Energy, Inc. and PRB Energy, Inc., dated May 1, 2006 (filed on Form 8-K filed July 7, 2006 and incorporated by reference herein)
10.18	Purchase and Sale Agreement between PRB Energy, Inc., and Arête Industries Inc., dated September 1, 2006

10.19	Letter Agreement between PRB Energy, Inc., and Maverick Pipeline LLC, dated August 1, 2006
(10.20)	Purchase and Sale Agreement by and between Lance Oil & Gas Company, Inc., Western Gas Resources, Inc. and PRB Oil & Gas, Inc. dated December11, 2006. (filed as an exhibit to Form 8-K filed on January 5, 2007 and incorporated by reference herein)
(10.21)	Securities Purchase Agreement, dated December 28, 2006, by and among PRB Oil & Gas, Inc., PRB Energy, Inc., and the Buyers named therein (filed as an exhibit to Form 8-K filed on January 5, 2007 and incorporated by reference herein)
(10.22)	Master Gas Compression Contract, dated February 12, 2007, by and between PRB Gathering, Inc. and J-W Power Company (filed as and exhibit to Form 8-K filed on February 14, 2007 and incorporated by reference herein)
21.1	List of the Company s subsidiaries
23.1	Consent of Hein & Associates LLP
23.2	Consent of Ehrhardt Keefe Steiner & Hottman PC
23.3	Consent of Netherland, Sewell & Associates, Inc.
23.4	Consent of Sproule Associates Limited on behalf of Sproule Associates Inc.
24.1	Power of Attorney, incorporated by reference to Signature page attached hereto
31.1	Chief Executive Officer Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Principal Financial Officer Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

These exhibits are available upon request. Exhibits identified in parentheses below are on file with the SEC and are incorporated herein by reference. All other exhibits are provided as part of this electronic submission.

( ) Previously filed.

* Management contract or compensatory plan or arrangements.

26

SIGNATURES

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

	PRB Energy, Inc. (Registrant)
Date: March 29, 2007	/s/ Daniel D. Reichel Daniel D. Reichel *Vice President Finance*

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Daniel D. Reichel as his attorney-in-fact, with full power of substitution, for him in any and all capacities to sign any amendments to this Report on Form 10-K, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that said attorneys-in-fact, or their substitutes, may do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1934, this report has been signed on March 29, 2007 by the following persons in the capacities indicated.

Signature	**Title**
/s/ Robert W. Wright Robert W. Wright	Chairman and Chief Executive Officer
/s/ William F. Hayworth William F. Hayworth	President, Chief Operating Officer and Director
/s/ Gus J. Blass, III Gus J. Blass, III	Director
/s/ Paul L. Maddock, Jr. Paul L. Maddock, Jr.	Director
/s/ Sigmund J. Rosenfeld Sigmund J. Rosenfeld	Director
/s/ Reuben Sandler Reuben Sandler	Director
/s/ James P. Schadt James P. Schadt	Director
/s/ Joseph W. Sheehan Joseph W. Skeehan	Director

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors
PRB Energy, Inc.
Denver, Colorado

We have audited the consolidated balance sheet of PRB Energy, Inc. and subsidiaries as of December 31, 2006, and the related consolidated statements of income, retained earnings and cash flows for the year then ended. 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 audit.

We conducted our audit 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides 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 PRB Energy, Inc. and subsidiaries as of December 31, 2006, and the results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the accompanying consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*.

/s/ Hein & Associates LLP
***HEIN** & ASSOCIATES LLP*

Denver, Colorado
March 29, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
PRB Gas Transportation, Inc. and subsidiary
Denver, Colorado

We have audited the accompanying consolidated balance sheet of PRB Gas Transportation, Inc. and its subsidiary as of December 31, 2005 and the related consolidated statements of operations, changes in stockholders equity and cash flows for each of the years in the two-year period ended December 31, 2005. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with 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 includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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 PRB Gas Transportation, Inc. and its subsidiary as of December 31, 2005, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 7 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, effective December 31, 2005.

/s/ Ehrhardt Keefe Steiner & Hottman PC

March 30, 2006

PRB Energy, Inc.
Consolidated Balance Sheets
(In thousands except share amounts)

	December 31, 2006	December 31, 2005
Assets		
Current assets:		
Cash and cash equivalents	$ 11,157	$ 6,434
Restricted cash	2,078	
Accounts receivable, net	2,527	789
Inventory, net		1,346
Prepaid expenses	789	194
Total current assets	16,551	8,763
Oil and gas properties accounted for under the successful efforts method of accounting:		
Proved properties	5,436	317
Unproved leaseholds	9,282	136
Wells-in-progress	5,794	1,081
Total oil and gas properties	20,512	1,534
Less: accumulated depreciation, depletion and amortization	(766)	(3)
Net oil and gas properties	19,746	1,531
Gathering and other property and equipment:	11,603	6,992
Less: accumulated depreciation and amortization	(1,919)	(968)
Net gathering and other property and equipment	9,684	6,024
Other non-current assets:		
Deferred debt issuance costs	2,086	
Less: accumulated amortization	(375)	
Net deferred debt issuance costs	1,711	
Other non-current assets	2,151	1,122
Total other non-current assets	3,862	1,122
TOTAL ASSETS	$ 49,843	$ 17,440
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 1,854	$ 1,652
Accrued expenses and other current liabilities	979	97
Total current liabilities	2,833	1,749
Secured notes, debentures and other debt, less current portion	36,972	17
Discount on debentures	(4,326)	
Other non-current liabilities	3,140	417
Total liabilities	38,619	2,183
Commitments and Contingencies		
Stockholders equity		
Capital, 50,000,000 shares authorized, par value $0.001, 5,639,000 shares undesignated Series A, B and C Convertible Preferred, 4,361,000 shares authorized; 0 and 40,000 issued and outstanding, respectively		*
Common stock, 40,000,000 shares authorized; 8,231,894 issued; 8,601,994 and 7,431,894 outstanding, respectively	10	8
Treasury stock	(1,257)	(800)
Additional paid-in-capital	26,406	21,325
Accumulated deficit	(13,935)	(5,276)
Total stockholders equity	11,224	15,257
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 49,843	$ 17,440

* amounts less than one thousand

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

F-2

PRB Energy, Inc.
Consolidated Statements of Operations
(In thousands except per share amounts)

	Years Ended December 31, 2006	2005	2004
Revenue:			
Natural gas sales	$ 1,676	$ 51	$
Gas gathering and processing	2,612	2,834	1,840
Other	547	270	692
Total revenue	4,835	3,155	2,532
Natural gas gathering expense	340	12	
Natural gas production taxes	182	5	
Net revenue	4,313	3,138	2,532
Operating expenses:			
Gas gathering and processing	2,469	1,755	1,314
Natural gas lease operating expense	1,266	17	
Asset impairment charge	790	2,487	
Exploration expense	50	450	
Depreciation, depletion, amortization and accretion	2,332	1,067	656
General and administrative	5,026	2,029	1,184
Total operating expenses	11,933	7,805	3,154
Operating loss	(7,620)	(4,667)	(622)
Other income (expense):			
Interest and other income	1,248	167	29
Interest expense	(2,287)	(49)	(58)
Total other (expense) income	(1,039)	118	(29)
Net loss before cumulative effect of change in accounting principle	(8,659)	(4,549)	(651)
Cumulative effect of change in accounting principle		(76)	
Net loss	(8,659)	(4,625)	(651)
Convertible Preferred stock dividends and deemed dividends		(204)	(1,212)
Net loss applicable to common stockholders	$ (8,659)	$ (4,829)	$ (1,863)
Net loss per share of common stock before cumulative effect of change in accounting principle	$ (1.16)	$ (0.68)	$ (1.33)
Cumulative effect of change in accounting principle per share of common stock		(0.01)	(0.00)
Net loss per share basic and diluted	$ (1.16)	$ (0.69)	$ (1.33)
Basic and diluted weighted average shares outstanding	7,447,940	6,959,025	1,398,907

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

PRB Energy, Inc.
Statements of Stockholders Equity
Years Ended December 31, 2006, 2005 and 2004
(In thousands except share amounts)

	Series A	Series B	Series C	Common Stock	Treasury Stock	Additional Paid-in-capital	Accumulated Deficit	Stockholders Equity
Balance at January 1, 2004	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Series A shares issued for cash (2,400,000 shares)	2					4,985		4,987
Series B shares issued for cash (1,550,000 shares)		2				4,639		4,641
Serice C shares issued for cash (411,000 shares)			*			1,231		1,231
Common stock shares issued for cash (1,600,000 shares)				2		18		20
Purchase of treasury stock (800,000 shares)				*	(800)			(800)
Deemed capital contribution related to Series A dividend						63		63
Deemed capital contribution related to Series C issuance						1,027		1,027
Issuance of warrants for consulting services						12		12
Series A dividends						(375)		(375)
Series B dividends						(116)		(116)
Series C deemed dividend						(587)		(587)
Accrued dividends on preferred stock						(134)		(134)
Net loss							(651)	(651)
Balance at January 1, 2005	**2**	**2**	*****	**2**	**(800)**	**10,763**	**(651)**	**9,318**
Series A conversion to common stock (2,400,000 shares)	(2)			2				
Series B conversion to common stock (1,550,000 shares)		(2)		2				
Series C conversion to common stock (371,000 shares)			*	*				
Common stock shares issued for cash (2,300,000 shares)				2				2
Exercise of warrants and options (10,894 shares)				*		28		28
Series A Preferred stock dividends						(139)		(139)
Series B Preferred stock dividends						(65)		(65)
Proceeds from initial public offering, net of offering costs						10,738		10,738
Net loss							(4,625)	(4,625)
Balance at December 31, 2005			*****	**8**	**(800)**	**21,325**	**(5,276)**	**15,257**
Series C conversion to common stock (40,000 shares)			*	*				
Issuance of warrants						163		163
Share-based compensation						593		593
Common stock shares issued for debt financing (1,250,000 shares)				1		4,325		4,326
Purchase of common shares for cash (119,900 shares)				*	(457)			(457)
Net loss							(8,659)	(8,659)
Balance at December 31, 2006	**$**	**$**	**$**	**$ 10**	**$ (1,257)**	**$ 26,406**	**$ (13,935)**	**$ 11,224**

* amounts less than one thousand

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

PRB Energy, Inc.
Consolidated Statements of Cash Flows
(In thousands)

	Years Ended December 31, 2006	2005	2004
Cash flows from operating activities			
Net loss	$ (8,659)	$ (4,625)	$ (651)
Adjustments to reconcile net loss to net cash (used in) provided by operating activities:			
Depreciation, depletion, amortization and accretion	2,332	1,067	656
Asset impairment charge	790	2,487	
Exploration expense	50	450	
Amortization of debt issuance costs	375		
Bad Debt Expense	605		
Share-based compensation expense	663		
Warrants issued for services rendered	45		
Capitalized interest	(135)		
Cumulative effect of change in accounting principle		76	
Deemed compensation			441
Gain on sale of assets	(311)	(2)	
Changes in assets and liabilities:			
Accounts receivable	(1,943)	(366)	(423)
Inventory	1,346	(1,346)	
Prepaid expenses	(595)	(90)	(104)
Other non-current assets	(118)	(19)	(4)
Accounts payable	201	1,514	157
Accrued expenses and other current liabilities	621	73	
Deferred revenue	69		
Other non-current liabilities	308		
Net cash (used in) provided by operating activities	(4,356)	(781)	72
Cash flows from investing activities			
Capital expenditures	(5,270)	(1,979)	(41)
Acquisition of natural gas properties and gathering facilities	(17,453)	(336)	(10,606)
Restricted cash related to future liabilities of acquired properties	(3,078)		
Sale of gathering and fixed assets	350	17	
Net cash used in investing activities	(25,451)	(2,298)	(10,647)
Cash flows from financing activities			
Proceeds from IPO, net of issuance costs		11,007	
Proceeds from convertible notes and senior secured debentures	36,965		
Issuance costs related to convertible notes and senior secured debentures	(1, 968)		
Deferred costs of raising capital			(255)
Repurchase of common stock	(457)		
Repurchase of treasury stock			(800)
Proceeds from issuance of common stock		28	20
Proceeds from issuance of Series A, B and C Convertible Preferred Stock			10,859
Borrowings under bank loan and financing agreement		50	
Repayment of bank loan		(1,550)	1,500
Repayment of term loan	(10)		
Dividends		(338)	(429)
Repayment of retail installment sale contract		(4)	
Net cash provided by financing activities	34,530	9,193	10,895
Net increase in cash	4,723	6,114	320
Cash beginning of year	6,434	320	
Cash end of year	$ 11,157	$ 6,434	$ 320
Supplemental disclosure of cash flow activity			
Cash paid for interest	1,924	49	58
Supplemental schedule for non-cash activity			

Issuance of warrants in connection with public offering		571	
Issuance of warrants in connection with convertible notes	92		
Conversion of Series A, B and C Convertible Preferred stock	*	4	
Common stock issued related to financing of acquisition	4,326		
Capital remediation costs	1,333		
Asset retirement obligations	2,805	318	60
Retail installment sale contract used to purchase vehicle		31	

* amounts less than one thousand

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

PRB ENERGY, INC.
Notes to Consolidated Financial Statements
December 31, 2006

Note 1 General

PRB Energy, Inc. and its subsidiaries (PRB, PRB Energy, the Company, us, our or we) operate as an independent energy company engag the acquisition, exploitation, development and production of natural gas and oil. In addition, we provide gas gathering, processing and compression services for properties we operate and for third-party producers. We were initially incorporated in Nevada under the name PRB Transportation, Inc. in December 2003. On June 14, 2006, we changed our name to PRB Energy, Inc. Our common stock is traded on the American Stock Exchange (AMEX) under the ticker symbol PRB. PRB Energy operates as two business segments through two wholly-owned subsidiaries, PRB Oil and Gas, Inc., a Colorado corporation, a gas and oil exploitation and production company (E&P), formed in July, 2005, and PRB Gathering, Inc., a Colorado corporation, a gathering and processing company (G&P), formed in August 2006. We conduct our business activities in Wyoming, Colorado and Nebraska.

Note 2 Summary of Significant Accounting Policies

Basis of Presentation - The consolidated financial statements include the accounts of the Company and its subsidiaries. All material inter-company transactions have been eliminated. Certain prior period amounts have been reclassified to conform to the current financial statement presentation.

Use of Estimates - The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and cash equivalents - The Company considers all highly liquid instruments purchased with an original maturity of three months or less to be cash equivalents. The Company continually monitors its positions with, and the credit quality of, the financial institutions with which it invests. As of the balance sheet date, and periodically throughout the year, the Company has maintained balances in various operating accounts in excess of federally insured limits.

Accounts receivable - Trade accounts receivable are recorded at the invoiced amount. The Company does not have any off-balance-sheet credit exposure related to its customers. The Company assesses credit risk and allowance for doubtful accounts on a customer specific basis. As of December 31, 2005, the Company did not have an allowance for doubtful accounts. As of December 31, 2006 the Company has a combined total allowance for doubtful accounts of $605,000 due to evaluation of collection on some customer accounts. Of this allowance for doubtful accounts, $596,000 pertains to Rocky Mountain Gas, Inc. (RMG). RMG s receivables totaled $791,000 at December 31, 2006 and the remaining balance, after the allowance, of $195,000 is reflected in the consolidated financial statements.

Five individual customers accounted for 81% of total sales and no other individual customer accounted for 10% or more of total sales for the year ended December 31, 2006. One individual customer accounted for 54% of total sales and no other individual customer accounted for 10% or more of total sales for the year ended December 31, 2005.

As of December 31, 2006, JMG Exploration, Inc. (JMG) had an outstanding balance due of $107,000 for interest charges related to certain gas gathering pipe held by a third party for resale. The pipe was originally purchased jointly by the Company and JMG for a gas gathering project in 2005. Under a letter agreement dated March 18, 2006, JMG agreed to indemnify the Company against any costs associated with the sale of the pipe, including any carrying and storage costs of the pipe. The agreed upon interest rate to be charged JMG was 10% per annum. The interest was charged from October 28, 2005 to date on the costs incurred by the Company, less any proceeds from the sale of the pipe. The pipe inventory was sold during 2006 and the proceeds were received by the Company and credited to the inventory account.

The Company grants credit in the normal course of business to customers in the United States. The Company periodically performs credit analysis and monitors the financial condition of its customers to reduce credit risk. Management periodically reviews accounts receivable aging reports to assess credit risks, and if appropriate, also reviews updated credit information to further assess such risk. In the event that management determines the customers accounts receivable collectibility as less than probable, management reduces the carrying amount by a valuation allowance that reflects management s best estimate of the amount that may not be collectible. Allowances for uncollectible accounts receivable are based on information available and historical experience. For information on the concentration of credit risk by customer in the years ended December 31, 2006 and 2005 respectively please see Note 3 of these consolidated financial statements.

Inventory - Inventory is recorded at the lower of cost or market. The Company periodically reviews the carrying cost of its inventories as compared to current market value for those inventories and adjusts its carrying value to the lower of cost or market. At December 31, 2006 the Company had no inventory.

Income Taxes - In accordance with SFAS No. 109, Accounting for Income Taxes (SFAS No. 109), the Company recognizes deferred tax liabilities and assets based on the differences between the tax basis of assets and liabilities and their reported amounts in the consolidated financial statements that will result in taxable or deductible amounts in future years. In evaluating the ability to realize net deferred tax assets, the Company will take into account a number of factors, primarily relating to the Company s ability to generate taxable income. The Company has not recorded a deferred tax asset attributable to the net operating loss for the years ended December 31, 2006 and December 31, 2005 as it is more likely than not that a deferred benefit will not be realized.

Revenue Recognition - The Company recognizes gas gathering revenue at the time when the service is rendered. The Company recognizes revenue from the sale of natural gas during the period the sale of the product occurs and title transfers to the buyer. The Company recognizes management services revenue when the service is provided.

Property, Equipment and Contracts Gas Gathering and Other - The Company periodically reviews carrying values of long-lived assets for impairment. Gathering assets are depreciated over 10 years.

Other property and equipment, such as office furniture, computer and related software and equipment, automobiles and leasehold improvements are recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets or underlying leases in respect to leasehold improvements, ranging from 3 to 10 years.

Amortization of contracts is calculated using the straight-line method over the term of the underlying contracts or the estimated life of production over ten years.

Oil and Gas Producing Properties - The Company has elected to follow the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred. If an exploratory well does not find proved reserves, the costs of drilling the unsuccessful exploratory well are charged to expense. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures in the consolidated statements of cash flows. The cost of development wells, whether productive or not, is capitalized. Geological and geophysical costs and the cost of carrying and retaining unproved properties are expensed as incurred.

Depreciation, depletion and amortization (DD&A) of capitalized costs of proved oil and gas properties is determined on a field-by-field basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement and abandonment costs and the anticipated proceeds from equipment salvage. The Company has adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143) which provides guidance on accounting for dismantlement and abandonment costs and FASB Interpretation 47, Accounting for Conditional Asset Retirement Obligations (FIN No. 47) which provides guidance in determining estimated dismantlement and abandonment costs in situations where the method and timing of settlement are uncertain. See Note 7 Asset Retirement Obligations.

Impairment of Long-Lived Assets - In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the Company groups assets at the field level and periodically reviews the carrying value of its property and equipment to test whether current events or circumstances indicate that such carrying value may not be recoverable. If the tests indicate that the carrying value of the asset is greater than the estimated future undiscounted cash flows to be generated by such asset, then an impairment adjustment needs to be recognized. Such adjustment consists of the amount by which the carrying value of such asset exceeds its fair value. The Company generally measures fair value by considering sale prices for similar assets or by discounting estimated future cash flows from such asset using an appropriate discount rate. Considerable management judgment is necessary to estimate the fair value of assets, and accordingly, actual results could vary significantly from such estimates. When assets are sold, the applicable costs and accumulated depreciation and depletion are removed from the accounts and any gain or loss is included in income. Expenditures for maintenance and repairs are expensed as incurred.

The Company reviews its long-lived assets and other intangible assets with long lives for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recovered. An impairment loss is recognized only if the carrying value of the asset is not recoverable and exceeds its fair market value. The Company estimates the fair market value of its long-lived assets using expected future discounted cash flows.

Exploration Expense - The Company accounts for exploration and development activities utilizing the successful efforts method of accounting. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found proved reserves in commercial quantities. The application of the successful efforts method of accounting requires managerial judgment to determine that proper classification of wells designated as developmental or exploratory is made to determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive but actually deliver oil and gas in quantities insufficient to be economic. This may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. The evaluation of oil and leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

Asset Retirement Obligations - The Company follows SFAS No. 143 and FIN No. 47. Estimated future asset abandonment costs are discounted to present values using a risk-adjusted rate over the estimated economic life of the assets. Such costs are capitalized as part of the cost of the related asset and amortized over the related asset s estimated useful life. The associated liability is classified as a long-term liability and is adjusted when circumstances change and for the accretion of expense which is recorded as a component of depreciation, depletion and amortization. The Company recognizes an estimate of the liability associated with the abandonment of oil and gas properties at the time the well is completed. The Company estimated its asset retirement obligation liabilities for these wells based on estimated costs to plug and abandon the wells and its respective ownership percentage in the wells.

Stock-Based Compensation - At December 31, 2006, the Company had a stock-based employee compensation plan that includes stock options issued to employees and non-employee Directors as more fully described in Note 12 Compensation Plans. Prior to 2006, the Company had accounted for stock-based compensation using the intrinsic value recognition and measurement principles detailed in Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees and related interpretations. No stock-based compensation expense relating to stock options has been reflected in the Company s statements of operations for any period presented as all options granted under the plan had an exercise price equal to or higher than the market value of the underlying common stock on the date of grant. The Company currently uses the Black-Scholes option valuation model to calculate required disclosures. As of January 1, 2006, the Company has adopted the provisions of SFAS No. 123R, Share-Based Payment (SFAS No. 123R). This statement requires the Company to record compensation expense associated with the fair value of stock-based compensation. As a result of the adoption of SFAS No. 123R, the Company expects to record compensation expense associated with all unvested stock options totaling $605,000 in future periods under the modified-prospective adoption method.

In respect to the pro forma disclosures herein, the options are amortized to expense over the options vesting periods. Future actual amounts may differ from the pro forma disclosures. The following table illustrates the pro forma effect on net loss and loss per share if the Company had applied the fair value recognition provisions of SFAS No. 123, Accounting for Stock Based Compensation (SFAS No. 123) to stock-based employee compensation:

	For the Year Ended December 31,	
	2005	**2004**
(in thousands, except per share amounts)		
Net loss applicable to common stockholders:		
As reported	$ (4,829)	$ (1,863)
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	534	38
Pro forma net loss	$ (5,363)	$ (1,901)
Pro forma basic and diluted earnings per share	$ (0.77)	$ (1.36)

For purposes of pro forma disclosures, the estimated fair values of the options are amortized to expense over the options vesting periods. The effects of applying SFAS No. 123 in the pro forma disclosure are not necessarily indicative of actual future amounts, particularly since the future amortization expense is less than was recorded in 2006, as described above.

Net Loss Per Share - The Company accounts for earnings (loss) per share (EPS) in accordance with SFAS No. 128, Earnings per Share (SFAS No. 128). Under SFAS No. 128, basic EPS is computed by dividing the net loss attributable to common stockholders by the weighted average common shares outstanding without including any potentially dilutive securities. Diluted EPS is computed by dividing the net loss for the period by the weighted average common shares outstanding plus, when their effect is dilutive, common stock equivalents.

Potentially dilutive securities, which have been excluded from the determination of diluted earnings per share because their effect would be anti-dilutive, are as follows:

	For the years ended December 31, 2006	2005	2004
Series A Convertible Preferred			2,400,000
Series B Convertible Preferred			1,550,000
Series C Convertible Preferred		40,000	411,000
Convertible subordinated	3,137,857		
Warrants	300,000	230,000	45,000
Options	617,250	463,250	220,000
Total potentially dilutive shares excluded	4,055,107	733,250	4,626,000

Subsequent to December 31, 2006 the Company issued the following dilutive securities, which would have increased the number of potentially dilutive shares excluded (above), if these securities were issued prior to December 31, 2006:

	Potential Common Shares
Warrants	15,000
Options	172,500
Total	187,500

Off-Balance Sheet Arrangements - As part of its ongoing business, the Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities (SPEs), or SPEs which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of December 31, 2006, the Company has not been involved in any unconsolidated SPE transactions.

Recent Accounting Pronouncements

In December 2004, the FASB issued SFAS No. 123R. SFAS No. 123R requires that compensation costs relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. SFAS No. 123R covers a wide range of share-based compensation arrangements including share options, restricted share plans, performance-based awards, share appreciation rights and employee share purchase plans. Effective April 2005, the Securities and Exchange Commission extended the implementation date to the beginning of a registrant s next fiscal year beginning after June 15, 2005. The provisions of SFAS No. 123R were adopted by the Company effective January 1, 2006. As a result of the adoption of SFAS No. 123R, the Company recorded compensation expense associated with unvested stock options totaling $685,000 under the modified-prospective adoption method.

In March 2005, the FASB issued FIN No. 47 which clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This Interpretation is effective for years ended December 15, 2005 or later. The Company adopted this Interpretation effective December 31, 2005. See Note 7 Asset Retirement Obligations.

In May 2005, the FASB, as part of an effort to conform to international accounting standards, issued SFAS No. 154, *Accounting Changes and Error Corrections* (SFAS No. 154), which is effective for the Company beginning on January 1, 2006. SFAS No. 154 requires that all voluntary changes in accounting principles be retrospectively applied to prior financial statements as if that principle had always been used, unless it is impracticable to do so. When it is impracticable to calculate the effects on all prior periods, SFAS No. 154 requires that the new principle be applied to the earliest period practicable. The adoption of SFAS No. 154 did not have a material effect on the Company s financial position or results of operations.

SFAS No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, specifies that drilling costs for completed exploratory wells should be expensed if the related reserves cannot be classified as proved within one year unless certain criteria are met. In April 2005, the FASB issued FASB Staff Position 19-1, Accounting for Suspended Well Costs (FSP 19-1). FSP 19-1 provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved. FSP 19-1 is effective for all reporting periods beginning after April 4, 2005, and the Company adopted FSP 19-1 upon incurrence of initial exploratory drilling costs during the fourth quarter of 2005.

In June 2006, the FASB issued Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. This interpretation requires that realization of an uncertain income tax position must be more likely than not (i.e. greater than 50% likelihood of receiving a benefit) before it can be recognized in the financial statements. Further, this interpretation prescribes the benefit to be recorded in the financial statements as the amount most likely to be realized assuming a review by tax authorities having all relevant information and applying current conventions. This interpretation also clarifies the financial statement classification of tax-related penalties and interest and sets forth new disclosures regarding unrecognized tax benefits. This interpretation is effective for fiscal years beginning after December 15, 2006, and the Company will be required to adopt this interpretation in the first quarter of 2007. Based on the Company s evaluation as of December 31, 2006, it does not believe that the implementation of FIN 48 will have a material impact on its financial statements.

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements* was issued by the Financial Accounting Standards Board (FASB). This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 will become effective for the fiscal year beginning January 1, 2008, and the Company is currently assessing the potential impact of this Statement on the financial statements.

In September 2006, Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*. Registrants must quantify the impact on current period financial statements of correcting all misstatements, including both those occurring in the current period and the effect of reversing those that have accumulated from prior periods. This SAB was adopted at December 31, 2006. The adoption of SAB No. 108 had no effect on the financial position or on the results of operations.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, which permits an entity to measure certain financial assets and financial liabilities at fair value. The objective of SFAS No. 159 is to improve financial reporting by allowing entities to mitigate volatility in reported earnings caused by the measurement of related assets and liabilities using different attributes, without having to apply complex hedge accounting provisions. Under SFAS No. 159, entities that elect the fair value option (by instrument) will report unrealized gains and losses in earnings at each subsequent reporting date. The fair value option election is irrevocable, unless a new election date occurs. SFAS No. 159 establishes presentation and disclosure requirements to help financial statement users understand the effect of the entity s election on its earnings, but does not eliminate disclosure requirements of other accounting standards. Assets and liabilities that are measured at fair value must be displayed on the face of the balance sheet. This statement is effective beginning January 1, 2008 and the Company is evaluating this pronouncement.

Note 3 Concentration of Credit Risk

The Company sells gas and natural gas liquids to pipelines, refineries and oil companies. Credit is extended based on an evaluation of the customer s financial condition and historical payment record.

Revenues from customers which represented 10% or more of the Company s sales for the three and year ended December 31, 2006 and 2005 were as follows:

Customer	**For the year ended December 31, 2006**	**2005**
	(% of total revenue)	
A Exploration and production	22.2 %	
B Gathering and Processing	13.2 %	54 %
C Gathering and Processing	21.2 %	
D Exploration and production	13.4 %	
E Gathering and Processing	11.4 %	

The Company does not believe that the loss of any one customer would impact us marketability.

Note 4 Acquisitions

Recluse

In the first quarter of 2006, the Company acquired 2 gas gathering systems in the Recluse area of Wyoming (together Recluse gathering system) for approximately $1.5 million. Also, in 2 separate transactions totaling $183,000, the Company acquired a combination of working interests ranging from 7.5% to 15% in the development of approximately 5,600 net acres in the Recluse and Gap areas that offer us the opportunity to expand both E&P and G&P activities.

True Oil Pipeline

The Company acquired approximately 70 miles of gathering lines in the Recluse, Wyoming area of the Powder River Basin which will provide gathering opportunities on over 100,000 acres. The transaction is closed on July 15, 2006 and was effective as of July 1, 2006. The purchase price for these assets was $428,100 and was funded by cash on hand. The associated ARO booked for the pipeline was $171,000 in accordance with SFAS No. 143. The purchase was recorded using the purchase method of accounting under SFAS No. 141. The purchase price, including legal fees and other professional fees incurred, was allocated to the pipeline.

Gap, Bonepile, Bellnob Fields

On June 30, 2006, the Company acquired working interests in approximately 580 gross (529 net) coal-bed methane (CBM) wells on approximately 29,000 acres located in the Powder River Basin of Wyoming from Pennaco Energy, Inc. (Pennaco). The purchase price of the acquired interests was approximately $600,000 and the effective date was July 1, 2006. As part of the purchase agreement, the Company issued a $3 million reducing letter of credit for the benefit of Pennaco to guarantee the funding of the future liability of the plugging costs of wells purchased from Pennaco. The asset retirement obligation of these wells has been recorded on the balance sheet for $2 million based on the discounted present value of the future liability. The letter of credit is collateralized by a $3 million certificate of deposit (CD) and is considered restricted cash for purposes of available working capital. The restricted amount of the CD will be released at the same rate annually that the letter of credit is reduced. A potion of the CD is classified under Other Non-current assets on the Balance Sheet for $1 million, based on the terms of the agreement. The remaining $2 million is considered a current asset, as the letter of credit is anticipated to be reduced by that estimated amount as of June 30, 2007 under the terms of the agreement.

Of the 580 gross wells acquired, fewer than 130 wells were commercially producing natural gas. The Company currently has approximately 220 wells on production.

The purchase was recorded using the purchase method of accounting under SFAS No. 141. The purchase price, including legal fees and other professional fees incurred, was allocated to the asset categories as outlined in the following table based on the estimated fair value of the assets acquired:

Asset category	**In thousands**
Proved Property ARO	$ 2,032
Producing Leasehold Costs	1,190
Lease and Well Equipment	746
Total	$ 3,966

Northeast Colorado Denver-Julesburg (D-J) basin Niobrara formation

In December 2006, PRB Oil & Gas, Inc. acquired producing wells and approximately 330,000 net acres in the D-J Basin, which is located in northeast Colorado and southwest Nebraska. This acquisition provides the Company with geographic diversity in operations. In addition, with the use of 3-D seismic, numerous potential conventional drilling locations have been identified. This acquisition also includes additional proprietary 2-D and 3-D seismic that the Company believes should provide low-risk exploitation.

In connection with the December 2006 acquisition, PRB Energy and PRB Oil & Gas, Inc. entered into a Securities Purchase Agreement with two private lenders. Pursuant to that agreement, PRB Oil & Gas, Inc. issued to the lenders $15 million of senior secured debentures (the Debentures) and PRB Energy issued to the lenders 1,250,000 shares of common stock. For more information regarding the issuance of the Debentures and the 1,250,000 shares of the Company s common stock, see Note 11 Stockholders Equity.

The purchase was recorded using the purchase method of accounting under SFAS No. 141. The purchase price, including legal fees and other professional fees incurred, was allocated to the asset categories as outlined in the following table based on the estimated fair value of the assets acquired:

Asset category	**In thousands**
Proved Property ARO	$ 186
Undeveloped Leasehold Costs	8,917
Producing Leasehold Costs	850
Lease and Well Equipment	1,933
Total	$ 11,886

Note 5 Property, Equipment and Contracts

Property and equipment consists of the following:

(in thousands)	**Useful Lives**	**December 31, 2006**	**December 31, 2005**
Compressor sites, pipelines and interconnect	1-10 years	$ 10,676	$ 6,806
Equipment in stock	5 years	26	
Computer equipment	3 years	313	29
Office furniture and equipment and related	5-7 years	254	97
Automobiles	3 years	334	60
		11,603	6,992
Less accumulated depreciation and amortization		(1,919)	(968)
Total		$ 9,684	$ 6,024

The Company s compressor sites, pipeline and equipment are in respect to G&P operations. Depreciation expense in respect to property and equipment totaled $974,000 and $843,000 for the years ended December 31, 2006 and 2005, respectively.

The Company reviewed the carrying value of the TOP system as associated revenue had declined due to decreasing producer volumes as well as the loss of a customer. Based on this review, the Company recorded an asset impairment charge of $2,487,000 relative to the TOP system during the year ended December 31, 2005. The impairment charge included $1,645,000 for property and equipment and $842,000 for contracts. The Company based its impairment on an independent evaluation of the fair market value of the system. As of September 1, 2006 the Company sold the system to Arête Industries, Inc. for $330,000 in cash. The net gain on the sale of $308,000 is reflected in Other Income in the December 31, 2006 consolidated financial statements.

Contracts valued at $1,280,000 (on the date of acquisition, August 2004) in respect to the BPE assets are being amortized over 10 years which is the estimated life of the contracts and the natural gas reserves underlying the contracts. Amortization expense in respect to contracts totaled $128,000 and $213,000 for the years ended December 31, 2006 and 2005, respectively. The amortization expense for the year ended December 31, 2005 included amortization of the TOP contracts through September 30, 2005, when the TOP contracts were impaired in full.

Gas Gathering and Transportation Contracts - *BPE*

The Company assumed a 10-year gas transportation contract with an unrelated third party, Bear Paw Energy, LLC (BPE) that was effective in September 2001. BPE transports customers gas for $0.14 per Mcf. The Company purchased certain assets from BPE effective August 1, 2004.

Future period amortization expense in respect to the BPE contracts is as follows:

Year ending December 31,	**In thousands**
2007	$ 128
2008	128
2009	128
2010	128
2011	128
Thereafter	331
Total	$ 971

Storm Cat Agreement

Effective January 1, 2006, we entered into a gas gathering services agreement (the Agreement) with Storm Cat Energy Corporation (Storm Cat) which requires Storm Cat to pay us gas gathering fees on specific minimum volumes of gas whether or not those volumes are delivered and transported through our system. The Agreement has a ten-year term, of which the first 5 years are non-cancelable. The Agreement requires Storm Cat to make minimum payments in 2006 during the first 3 years of the Agreement. The Agreement also provides for our gas gathering rates to decrease during the fourth and fifth years.

During the year ended December 31, 2006, we billed Storm Cat for actual volumes delivered. The Agreement allows for a cash true-up payment at each year end if the annual volume commitment under the Agreement is not met. We recognize revenues based on our estimate of the average gas gathering rate during the non-cancelable term of the Agreement. Accordingly, we deferred the gas gathering fees as a non-current liability on our balance sheet at December 31, 2006.

Note 6 Inventory

Inventory at December 31, 2005 of $1.3 million consisted of approximately 32 miles of 8-inch steel pipe that was purchased for an oil and gas pipeline project that was being planned to transport a customer s oil and gas production. The Company sold the balance of the inventory during 2006 at cost.

Note 7 Asset Retirement Obligations

During the years ended December 31, 2005 and 2006, the Company reviewed its asset retirement obligations in respect to its BPE assets and determined an estimate of those future liabilities as determined in accordance with FIN No. 47. The Company was previously unable to determine a reasonable estimate of the timing of future period estimated dismantlement liabilities in accordance with SFAS No. 143. Those future liabilities include the removal of pipelines and compressor stations per the associated contracts. The Company estimated its future obligations in respect to the BPE assets based on estimated probabilities that the surface-use agreement based obligation would occur and also assigned probabilities as to potential settlement dates. The agreements with the lessors include provisions allowing the lessor to decide at a future date whether the lessor requires that the Company dismantle its sites and lines. Accordingly, the Company recorded the estimated asset retirement obligation liabilities of $259,000 in respect to the BPE systems effective December 31, 2005, upon adoption of FIN No. 47. This included $76,000 of accretion and depreciation expense that has been recorded as a cumulative effect of change in accounting principle in the statement of operations for the year ended December 31, 2005. The $76,000 cumulative effect of change in accounting principle included $30,000 for the year ended December 31, 2004 and $46,000 for the year ended December 31, 2005.

The Company estimated its future obligation in respect to the True Oil pipeline in the Recluse area and recorded its estimated asset retirement obligation liabilities of $178,000 effective December 31, 2006. During the years ended December 31, 2006 and 2005, the Company also established asset retirement obligations in respect to oil and gas properties of $2.7 million and $59,000, respectively.

The following table details all changes to the Company s estimated asset retirement obligation liabilities during the years ended December 31, 2006 and 2005:

(in thousands)	For the Year Ended December 31, 2006	2005
Asset retirement obligations, beginning of period	$ 387	$ 65
Sale of TOP assets	(52)	
Cumulative effect of change in accounting principle BPE assets		259
Gathering assets	199	
Proved properties	2,292	59
Accretion expense	314	4
Asset retirement obligations, end of period	$ 3,140	$ 387

The Company will continue to review its asset retirement obligations and will adjust its estimates when facts and circumstances warrant.

Note 8 Income Taxes

Income tax benefit for each of the years ended December 31, 2006, 2005, and 2004 are as follows:

(in thousands)	2006	2005	2004
Current:			
Federal	$	$	$
State			
Total current income tax benefit			
Deferred:			
Federal & State	2,678	1,883	71
Valuation allowance	(2,678)	(1,883)	(71)
Total deferred income tax benefit			
Total income tax benefit	$	$	$

The reconciliation of the benefit for income taxes computed at the statutory rate to the provision for income taxes as shown in the financial statements of operations for the years ended December 31, 2006, 2005 and 2004 is as follows:

(in thousands)	2006	2005	2004
Computed at the estimated effective tax rate	$ 3,155	$ 1,619	$ 228
Permanent differences, changes in effective tax rate, and other	(477)	(14)	(157)
Valuation allowance	(2,678)	(1,605)	(71)
Income tax benefit	$	$	$

The components of the net deferred income tax assets (liabilities) are as follows:

(in thousands)	2006	2005	2004
Non-current assets (liabilities):			
Property and equipment	$ (591)	$ (215)	$ (276)
Oil and gas properties	(2,145)	(372)	
Contracts	38	331	18
Organization costs	11	15	2
Asset retirement obligations	1,162	135	23
Net operating loss carryforwards	5,863	1,987	304
Bonus accrual		2	
Bad debt expense	223		
Valuation allowance	(4,561)	(1,883)	(71)
Net deferred tax asset (liability)	$	$	$

At December 31, 2006 and 2005, the Company had net operating loss carry forwards, for federal income tax purposes, of approximately $16.0 million and $4.6 million, respectively. These net operating loss carry forwards, if not utilized to reduce taxable income in future periods, will expire in various amounts beginning in 2024 through 2026. This net operating loss carry forward may be subject to U.S. Internal Revenue Code Section 382 limitations.

The Company has established a valuation allowance for deferred taxes that offsets its net deferred tax assets as management currently believes that these losses will not be utilized in the near term. The allowance recorded was $2.7 million and $1.9 million for 2006 and 2005, respectively. The Company will continue to evaluate the reasonableness and appropriateness of the valuation allowance in future periods.

Note 9 Commitments and Contingencies

Rescission of Series C Convertible Preferred Stock Sale

In December 2004, the Company received $1.233 million from the sale of 411,000 shares of Series C Convertible Preferred stock. The Company paid no cash or other commissions or finders fees in connection with this offering. In the view of the SEC, this placement might not have been eligible for an exemption from registration under the Securities Act of 1933. In the absence of such an exemption, investors could bring suit against the Company to rescind their stock purchases, in which event the Company could be liable for rescission payments to these investors of up to $1.233 million exclusive of interest and costs. In August 2005, the Company filed a registration statement on Form S-1 to register the underlying shares of common stock issuable upon conversion of the Series C Convertible Preferred stock. The SEC declared the S-1 effective on August 16, 2005. As of December 31, 2005 and December 31, 2006, respectively, 371,000 shares and 40,000 shares of Series C Convertible Preferred had been converted to common shares.

Commitments

As a normal course of the Company s business operations, it entered into operating leases for office space, office equipment, vehicles and compression equipment. In addition, the Company has entered into service agreements that provide compression equipment and related services on a bundled basis. These agreements, which pertain to the BPE gas gathering systems, expired in 2006.

In addition, the Company is a party to surface-use and right-of-way agreements in respect to the gathering systems and E&P properties that are cancelable when gas volumes decline to a level where the contract is uneconomic to the Company. The Company has estimated that future minimum lease commitments under these agreements will expire in 2014 based on estimated reserves in place.

Rental payments under these operating leases and service agreements totaled $1.09 million and $1.78 million for the periods ended December 31, 2006 and 2005, respectively.

Future payments, by year, under these operating leases and service agreements are as follows:

	(in thousands)
2007	$ 674
2008	666
2009	644
2010	667
2011	501
Thereafter	2,024
Total	$ 5,176

Note 10 Borrowings

Senior Subordinated Convertible Notes (the Notes)

In March 2006, the Company issued the Notes of approximately $22 million in a private placement. The Notes are secured by certain gas gathering assets owned by the Company and mature 30 months from the date of issue. The Notes bear interest at a fixed rate of 10% per annum, payable quarterly in arrears beginning on March 15, 2006. A registration statement applicable to the shares of common stock underlying the Notes was filed in May 2006 and declared effective on June 21, 2006. The Notes do not contain any beneficial conversion features.

Debt issuance costs in the amount of $1.05 million, excluding the value of warrants issued, were deferred as other non-current assets and are being amortized as interest expense using the effective interest method over the 30-month life of each Note. For the year-ended December 31, 2006, the Company incurred $2 million in total interest expense applicable to the Notes.

Note holders have the right to convert the Notes to common stock at a conversion price of $7.00 per share, which is subject to certain anti-dilution adjustments. In the event that the common stock trades at $14.00 per share or above for 10 consecutive days, the Company has a call provision that allows us to retire the Notes upon 10 days prior written notice by paying in cash the principal amount and any accrued but unpaid interest. In addition, the Company is prohibited from declaring or paying cash dividends on the common stock during the period that one of the Notes is outstanding and unpaid.

The Company follows SFAS No. 133, and EITF 00-19, *Accounting for Derivative Financial Instruments Index to, and Potentially Settled in, a Company s Own Stock* and related pronouncements. The Company has evaluated the conversion feature embedded in the senior subordinated convertible Notes and the liquidated damages provision in the related Registration Rights Agreement and has determined that the entire amount of these securities is properly classified as long-term debt and are not accounted for as derivatives on the consolidated balance sheet at December 31, 2006.

Senior Secured Debentures (the Debentures)

In connection with the December 2006 acquisition of the NE Colorado Field in the Niobrara formation, the Company entered into a Securities Purchase Agreement with two private lenders. Pursuant to that agreement, the Company issued to the lenders $15 million of the Debentures and the Company issued to the lenders 1,250,000 shares of common stock, which are being offered pursuant to this prospectus. For more information regarding the issuance of the Debentures and the 1,250,000 shares of common stock, see Note 11 Stockholders Equity.

The Debentures mature and are due and payable on August 31, 2008 and bear interest at 13% per annum, which is due and payable quarterly in arrears. Subject to certain conditions, the Debentures can be prepaid by the Company with a premium for early prepayment of 110% of the principal amounts. Upon the occurrence of an event of default, as described in the Debentures, the payment of the principal amounts may be accelerated and the interest rate applicable to the principal amounts will be increased to 18% per annum during the period the default exists. A majority of the proceeds received from the lenders was used for the acquisition of the Niobrara formation properties on December 28, 2006 with the balance to be used for general corporate purposes. Refer to Part 1, Item 1-Business on Niobrara formation under Acquisitions and Divestitures.

Debt issuance costs in the amount of $1 million were deferred as other non-current assets and are being amortized as interest expense using the effective interest method over the 20-month life of each Note. For the year-ended December 31, 2006, the Company incurred $16,000 in total interest expense applicable to the Notes.

Pursuant to the terms of a Pledge and Security Agreement entered into by the Company and the lenders, the Debentures are collateralized by substantially all of the assets, except for certain excluded assets as described in the Pledge and Security Agreement. Pursuant to the terms of the Pledge and Security Agreement, the lenders are entitled to foreclose on, and take possession of the pledged assets if an event of default occurs. In addition, pursuant to the terms of the Secured Guaranty, the Company has agreed to jointly and severally guarantee performance under the Debentures and other transaction documents.

Promissory Note

On December 14, 2004, the Company signed a promissory note with the Bank of Oklahoma (BOK) for a $1.75 million revolving line of credit that was due on the earlier of March 31, 2005 or upon funding of its initial public offering. This promissory note was paid in full in April 2005 from proceeds from the initial public offering and the line of credit was withdrawn.

Stockholder Pledge of Certificate of Deposit

On December 14, 2004, a preferred stockholder pledged a certificate of deposit in the amount of $1.0 million as collateral for the BOK line of credit, as discussed above. The pledge was withdrawn upon payment of the BOK note in April 2005.

Retail Installment Sale Contract

On August 3, 2005, the Company purchased a vehicle using a 0% retail installment sale contract for a total of $31,000.

Maturities

Future debt maturities are reflected on the following table:

	(in thousands)
2007	$
2008	36,965
2009	
2010	
2011	
Thereafter	
Total	$ 36,965

Note 11 Stockholders Equity

Common Shares Issued for Debt Financing

On December 28, 2006, in connection with the acquisition of the D-J Basin properties, the Company entered into a securities purchase agreement (SPA) with two private lenders. Pursuant to the SPA, in exchange for $15 million of proceeds, The Company issued and sold to the lenders $15 million of Debentures and the Company issued and sold to the lenders 1,250,000 shares of common stock. The amount included in stockholders equity and as a discount on Debentures on the balance sheet on December 31, 2006 was $4,326,000 which represented the market value of the common stock issued to the lenders on December 28, 2006.

The shares of the Company s common stock issued to the lenders, at the time they were issued, represented 14.5% of our outstanding common stock on a fully diluted basis. The Company also entered into a Registration Rights Agreement with the lenders requiring us to file a registration statement registering the shares issued to the lenders for resale on behalf of them under the Securities Act of 1933. In the event that the registration statement is not declared effective within one hundred-fifty (150) days of December 28, 2006 or the effectiveness of the registration statement is not maintained, the Company is obligated to pay, on a pro rata basis, to each holder of the shares of common stock issued to the lenders certain delay payments described in the Registration Rights Agreement. Such delay payments shall not exceed, in the aggregate, $750,000. The registration statement was filed with the SEC on February 2, 2007 and the SEC staff comments were received and have been responded to on March 22, 2007.

Initial Public Offering

On April 12, 2005, the Company s registration statement on Form S-1 was declared effective by the SEC and the Company s stock began trading on the AMEX under the trading symbol PRB. The Company sold 2,300,000 shares of common stock, including 300,000 shares pursuant to the underwriter s exercise of its over-allotment option. In conjunction with the offering, holders of Series A and Series B preferred stock converted their shares into an equal number of registered common shares. The Company recorded proceeds of $10.2 million net of underwriter s discounts, commissions and expenses, including warrants valued at $583,000.

Dividends

None.

Warrants

On June 28, 2004, the Company granted 45,000 warrants to consultants as compensation for their work on the Company s initial public offering. These warrants have a five-year term with immediate vesting and an exercise price of $5.50. The estimated fair value of the warrants at December 31, 2004 was $12,000 based on the Black-Scholes option pricing model.

The Company entered into an underwriting agreement on April 12, 2005. The agreement called for the underwriter to purchase the shares on a firm commitment basis at an 8% discount to the offering price. The Company s underwriter also received a 3% non-accountable expense allowance of the aggregate offering price of the shares offered, excluding the 300,000 over-allotment shares. At the closing of the underwriting, the Company sold warrants to the underwriter to purchase 200,000 shares of common stock at a price of $0.0001 per warrant. The warrants have an exercise price of $6.875 (125% of the initial offering price) and are exercisable for 4 years from the first anniversary of the issuance, or within 2 years following the effective registration date of the shares underlying the warrants, whichever earlier. The estimated fair value of the warrants at issuance was $571,000 based on the Black-Scholes option pricing model.

During the year ended December 31, 2004, the Company recorded deferred offering costs of raising capital, with a corresponding increase in additional paid-in-capital in respect to the 45,000 warrants issued during that period, of $12,000. In respect to the 200,000 warrants issued during April 2005, the fair value of the warrants of $571,000 was also charged against additional paid-in-capital.

The following assumptions were used in determining the fair values of the warrants as described previously:

Risk-free interest rate (%)	3.89 %
Expected life (years)	5
Expected volatility (%)	25 %
Expected dividends	

Through December 31, 2006, 2005, and 2004, respectively, cumulative activity in respect to warrants is as follows:

	2006	**2005**	**2004**
Balance, beginning of year	230,000	45,000	
Issued	70,000	200,000	45,000
Exercised		(15,000)	
Balance, end of year	300,000	230,000	45,000

The warrants exercised during the year ended December 31, 2005 were exercised under the cashless exercise provision.

Note 12 Equity Incentive Plans

The Company has an Equity Incentive Plan (Option Plan). The Plan grants options to purchase shares of the Company s common stock to eligible employees, contractors and current and former members of the Board of Directors. There are 860,199 shares of the Company s common stock reserved for issuance under the Plan. There are no expired shares during the year of December 31, 2006.

All options granted to date under the Plan have been granted at exercise prices equal to or greater than the respective market prices of the Company s common stock on the grant dates. There were 284,000 shares exercisable under the Plan as of December 31, 2006. As of January 1, 2006, the Company has adopted the provisions of SFAS No. 123R, Share-Based Payment (SFAS No. 123R). This statement requires the Company to record compensation expense associated with the fair value of stock-based compensation. As a result of the adoption of SFAS No. 123R, the Company expects to record compensation expense associated with all unvested stock options totaling $605,000 in future periods under the modified-prospective adoption method.

The following table summarizes activity for options:

	For the Year Ended December 31, 2006		For the Year Ended December 31, 2005		For the Year Ended December 31, 2004	
	Number of Shares	Weighted Avg. Exercise Price	Number of Shares	Weighted Avg. Exercise Price	Number of Shares	Weighted Avg. Exercise Price
Outstanding, beginning of year	463,250	$ 6.74	220,000	$ 5.50		
Granted	323,500	$ 6.03	299,000	$ 7.59	220,000	$ 5.50
Forfeitures	(169,500)	$ 7.15	(50,750)	$ 6.51		
Exercised			(5,000)	$ 5.50		
Outstanding, end of year	617,250	$ 6.35	463,250	$ 6.74	220,000	$ 5.50
Exercisable, end of year	284,000	$ 6.40	227,500	$ 6.39	70,000	$ 5.50
Weighted-average fair value of options granted during the year	323,500	$ 4.02	299,000	$ 3.19	220,000	$ 0.82

The weighted average remaining contractual life for the options outstanding at December 31, 2006 and 2005, respectively is 6.5 years and 7.4 years. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options outstanding at December 31, 2006 and 2005, respectively, is $2.98 and $2.16. The weighted average fair value of options granted and exercisable at December 31, 2006 and 2005, respectively, is $2.46 and $1.63.

SFAS No. 123 establishes a fair value method of accounting for stock-based compensation plans through either recognition or disclosure. The Company accounts for stock-based compensation under the intrinsic value method pursuant to Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees (APB No. 25) and has elected to adopt SFAS No. 123 through compliance with the disclosure requirements set forth in the Statement. Because the exercise price of the Company s stock options equals the market price or higher of the underlying stock on the date of the grant, no compensation expense is recognized under APB No. 25. Pro forma information regarding net loss and loss per share is required by SFAS No. 123 and has been determined as if the Company had accounted for its employee stock options under the fair value method of that Statement. See Note 2 Summary of Significant Accounting Policies for pro forma information.

The fair value of options was measured at the date of grant using the Black-Scholes option-pricing model. The fair values of options granted and employee stock purchase plan shares issued were estimated using the following weighted-average assumptions:

Assumption	**December 31, 2006**		**December 31, 2005**		**December 31, 2004**	
Risk free interest rate (%)	4.31-5.25		3.9-4.5		3.89-4.73	
Volatility factor of the expected market price of the Company s common stock	69.45-80	%	25	%	25	%
Expected life of the options (in years)	5-10		5-10		5-10	
Expected dividend						

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models incorporate highly subjective assumptions including the expected stock price volatility. The Company s stock options have characteristics significantly different from those of traded options and, as changes in the subjective input assumptions can materially affect the fair value estimate, it is management s opinion that the valuations as determined by the existing models are different from the value that the options would realize if traded in the market.

Note 13 Disclosures about Oil and Gas Producing Activities

Costs Incurred in Oil and Gas Producing Activities

The Company commenced oil and gas activities during the year ended December 31, 2005. The Company has incurred the following costs, both capitalized and expensed, in respect to oil and gas property acquisition, exploration and development activities during the year ended December 31, 2006 and 2005, respectively:

	For the Years Ended December 31,			
(in thousands)	**2006**		**2005**	
Acquisitions:				
Proved	$	4,507	$	
Unproved	9,282		136	
Exploration	50		1,531	
Development costs	4,480		314	
	$	18,319	$	1,981

Included in the above costs are capitalized asset retirement obligations for the years ended December 31, 2006 and 2005, respectively of $2,248,000 and $59,000, respectively.

The following table sets forth certain information regarding the results of operations for oil and gas producing activities for the years ended December 31, 2006 and 2005, respectively:

	For the Years Ended December 31,					
(in thousands)	**2006**			**2005**		
Revenues, net	$	1,154		$	34	
Production Costs	(1,266		)	(17		)
Asset Impairment (1)	(790		)			
Exploration	(50		)	(450		)
Depreciation, Depletion & Accretion (2)	(1,039		)	(98		)
	$	(1,991	)	$	(531	)

Note (1): The $790,000 impairment charge represents the remaining net book value of the Reno/Dilts wells previously included in E&P property assets and located in the Powder River Basin With the production volumes leveling off, management determined that there was insufficient revenue projected to cover the operating expenses of the rental generators and the diesel. These uneconomical properties were subsequently shut in during the first quarter of 2007.

Note (2): Includes $764,000 of depreciation and depletion of well costs and $275,000 of accretion of asset retirement obligation for wells.

The following table details the net changes in capitalized exploratory well costs for the years ended December 31, 2006 and 2005, respectively:

	For the Years Ended December 31,	
(in thousands)	**2006**	**2005**
Beginning balance at January 1,	$ 1,081	$
Additions to capitalized exploratory well costs pending the determination of proved reserves		1,531
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(1,031)	
Capitalized exploratory well costs charged to expense	(50)	(450)
Ending Balance at December 31,	$	$ 1,081

All capitalized wells-in-progress at year-end 2006 were development wells.

In 2006, the drilling programs were related to development drilling due to acquired reserves and established drilling locations in producing or proved formations. At December 31, 2006, $4.8 million of development drilling costs remained capitalized as wells-in-progress. All wells-in-progress at December 31, 2006 were classified as development wells. All capital costs added during 2006 for wells-in-progress that are reflected on the balance sheet at year-end 2006 were incurred within one year. None of these wells are in areas requiring major capital expenditures before production could be anticipated. These wells have either been reclassified to proved producing properties, or are currently being completed and undergoing de-watering. The Company believes that after these wells are de-watered, it will be able to determine if proved reserves have been discovered. The Company estimates that in mid-2007 it will be able to make this determination.

During 2005, the exploratory CBM drilling pilot programs were begun. The Company charged $450,000 of these exploratory drilling costs, relating to 6 wells, to exploration expense. At December 31, 2005, $1.1 million of exploratory drilling costs remained capitalized as wells-in-progress pending the determination of proved reserves.

Oil and Gas Reserve Quantities (Unaudited)

The Company engaged independent geological and petroleum engineering consultants, Netherland, Sewell & Associates, Inc. (NSAI), in 2006, and Sproule Associates, Inc. (Sproule) in 2005, to estimate our natural gas reserves. The Company also reviewed the calculations and assumptions these consultants use to calculate the reserves. NSAI determined the 2006 year-end reserve information included on their report, Estimate of Reserves and Future Revenue as of December 31, 2006, and Sproule determined the 2005 year-end reserve information included on their report, Reserve and Economic Evaluation as of January 1, 2006.

The Company emphasizes that the reserve estimates are imprecise by their nature, and reserve estimates on new discoveries and developments are less precise than reserve estimates for existing fields. Accordingly, the Company expects these estimates to change as time passes and information as to actual well performance can be included in those future estimates. The NSAI report was based on the Henry Hub gas product price of $5.63 per million British Thermal Unit (MMBtu) in effect on December 31, 2006, held constant for the life of the properties and adjusted by lease for regional price differentials, energy content, and transportation and compression charges. As a result, net prices ranged from $3.16 to $3.86 in Wyoming and $5.14 in Colorado. Lease operating costs were also held constant in accordance with SEC guidelines.

Proved oil and gas reserves are estimates of recoverable quantities of oil, natural gas and natural gas liquids that are determined using engineering and geological data with reasonable certainty. The reserve estimates are based on existing economic and operating conditions and include only existing wells from known reservoirs with existing equipment and technology. All of the proved reserves in 2005 were located in the Powder River Basin area of Wyoming. In 2006 the Company added proved and unproved reserves in the Denver-Julesburg (D-J) Basin of northeastern Colorado and southwestern Nebraska.

The following table summarizes estimated proved reserves of gas in million cubic feet (MMcf) as of December 31, 2006:

(In MMcf)	**2006**	**2005(1)**
Proved developed and undeveloped:		
Beginning of year, January 1	396	
Revisions of previous estimates	706	
Purchases of reserves in place	4,967	
Discoveries		402
Production	(395)	(6)
End of year, December 31	5,674	396

(1) These amounts represent proved developed producing reserves.

As of December 31, 2006, 32% of the proved reserves are categorized as proved developed producing.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

SFAS No. 69, *Disclosures about Oil and Gas Producing Activities* (SFAS 69) details guidelines of how to determine the standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company follows these guidelines that are summarized as follows:

- Future cash inflows, production and development costs are determined by applying oil and gas prices and costs in effect at year-end, including overhead expense allocable, transportation, quality and basis differentials to the year-end quantities of oil and gas to be produced in the future;

- Future income taxes are estimated using current income tax rates and estimated future statutory depletion;

- Future operating and development costs are based on estimates of expenditures in developing and producing proved oil and gas reserves in place at year-end, assuming continuity of year-end economic conditions;

- The resulting cash flows are reduced to present value using a 10% discount rate; and

- The Company used the following gas prices as the year end price at Henry Hub of $5.63 per MMBtu for natural gas on an Mcf basis, as adjusted by lease for regional price differentials, energy content and transportation and compression charges:

- Niobrara Formation in NE Colorado = $5.14 per Mcf

- Powder River Basin North Field = $3.86 per Mcf

- Powder River Basin Gap/Bonepile acquired from Pennaco = $3.16 per Mcf

- Powder River Basin Recluse field = $3.36 per Mcf

The following summarizes the standardized measure of future net cash flows relating to its proved gas reserves as of December 31, 2006 as prescribed in SFAS No. 69:

(in thousands)	**2006**	**2005(1)**
Future cash flows	$ 19,235	$ 2,089
Future production costs	(7,394)	(878)
Future development costs	(4,283)	
Future abandonment costs		(75)
Future income taxes	(381)	(316)
Future net cash flows	7,177	820
Ten percent discount	(1,670)	(132)
Standardized measure of discounted future net cash flows	$ 5,507	$ 688

(1) These amounts represent proved developed producing reserves.

The following summarizes the changes in the standardized measure of discounted future net cash flows relating to its proved gas reserves as of December 31, 2006 as prescribed in SFAS No. 69.

(in thousands)	**2006**
Standardized measure - Beginning of year	$ 688
Sales and transfers, net of production costs	111
Net change in sales and transfer prices, net of production costs	(895)
Changes in future development costs	156
Revisions of quantity estimates	998
Accretion of discount	106
Net change in income taxes	334
Purchases of reserves in place	4,827
Changes in production rates (timing) and other	(818)
Standardized measure of discounted future net cash flows	$ 5,507

Note: The Company initiated its oil and gas activities during the year ended December 31, 2005.

Note 14 Segment Information

SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information* (SFAS No.131) establishes standards for the way in which public companies disclose certain information about operating segments in their financial reports. Consistent with SFAS No. 131, the Company has defined two reportable segments, described below, based on factors such as how the Company manages operations and how the chief operating decision makers view results. The Company considers the chief executive officer and the chief operating officer as the chief operating decision makers. During the third quarter of 2005, the Company entered into the oil and gas exploration and production segment and began producing and selling natural gas during the fourth quarter of 2005.

Oil and Gas Exploitation and Production Segment (E&P)

Beginning in the third quarter of 2005, the Company commenced operations in the exploitation and production segment. Operations in this segment include developing and producing natural gas from CBM wells. For the year ended December 31, 2006, our E&P segment operated in the Powder River Basin area of Wyoming.

Through a management services agreement with RMG, the Company earned management fee revenues that it has included under Corporate in the following table that details the performance of our segments. In March 2006, the Company elected to terminate the management services agreement; however, it agreed to continue to provide services under the agreement through June 30, 2006.

Gas Gathering and Processing Segment (G&P)

The Company owns and operates gas gathering and processing systems it acquired in 2004 and during the year ended December 31, 2006, as earlier described. The Company charges a fee to our customers for these services based on volumes of gas transported, based on a monthly minimum fee and/or based on the level of compression services provided. The Company has acquired gas gathering contracts that include operating leases in respect to surface-use rights that are cancelable in the event that gas gathering activities cease as a result of declining production. The Company also has cancelable purchase commitments with third party providers for future field operations, equipment and maintenance activities.

	For the Year Ended December 31, 2006			
	E & P	**G & P**	**Corporate**	**Total**
(in thousands)				
Revenues, net of production taxes and other	$ 1,154	$ 2,612	$ 547	$ 4,313
Operating expense	1,266	2,469		3,735
Asset impairment charge	790			790
Exploration expense	50			50
Depreciation, depletion, amortization and accretion	764	806	762	2,332
General and administrative			5,026	5,026
Operating loss	(1,716)	(663)	(5,241)	(7,620)
Interest and other, net			(1,039)	(1,039)
Net loss attributable to common stockholders	$ (1,716)	$ (663)	$ (6,280)	$ (8,659)
Identifiable assets:				
Oil and gas properties, net of DD&A	$ 19,746			$ 19,746
Property and equipment, net of DD&A		$ 6,912	$ 2,772	$ 9,684
Other non-current assets, net of amortization		$ 971	$ 1,180	$ 2,151

	For the Year Ended December 31, 2005			
	E & P	**G & P**	**Corporate**	**Total**
(in thousands)				
Revenues, net of production taxes and other	$ 51	$ 2,834	$ 270	$ 3,155
Operating expense	34	1,755		1,789
Asset impairment charge		2,487		2,487
Exploration expense	450			450
Depreciation, depletion, amortization and accretion	4	1,041	22	1,067
General and administrative			2,029	2,029
Operating loss	(437)	(2,449)	(1,781)	(4,667)
Interest and other, net			118	118
Cumulative effect of change in accounting principle		(76)		(76)
Net loss	(437)	(2,525)	(1,663)	(4,625)
Preferred stock dividends			204	204
Net loss attributable to common stockholders	$ (437)	$ (2,525)	$ (1,867)	$ (4,829)
Identifiable assets:				
Oil and gas properties, net of DD&A	$ 1,531			$ 1,531
Property and equipment, net of DD&A		$ 5,856	$ 168	$ 6,024
Other non-current assets, net of amortization		$ 1,099	$ 23	$ 1,122

Note 15 Related Persons Transactions

In October 2005, the Company and JMG Exploration, Inc. (JMG) entered into an agreement whereby the Company was to build and operate a 32 mile, 8-inch oil and gas pipeline in exchange for a cost-plus compensation arrangement negotiated on an arms length basis. Thomas J. Jacobsen, Joseph Skeehan and Reuben Sandler served on the Company s board as director and also served on the board of directors of JMG during 2005. Thomas Jacobsen retired from the Company s board on June 14, 2006. Joseph Skeehan and Rueben Sandler have continued of serve on the Company s board through 2006 and are current Company board members. In January 2006, this project was terminated. In order to reimburse the Company for its carrying cost of the pipe, the Company and JMG entered into an agreement whereby JMG will indemnify the Company for these costs and resale of the pipe. The interest rate applied was 10% per annum based on the remaining balance for the pipe that was held in inventory. As of December 31, 2006, JMG owed the Company is $107,000 for interest recorded in accounts receivable. The pipe inventory was sold during 2006 and the proceeds were received by the Company and credited to the inventory account.

Susan Wright, our Corporate Secretary and wife of the CEO, provides Corporate Secretary services to us on a contract basis. During the year ended December 31, 2006 and 2005, Mrs. Wright was paid $81,000 and $19,000, respectively, for contract services.

In February 2006, we issued 40,000 warrants to a former director for services rendered in respect to our recent convertible debt offering. These warrants vested one year from the date of grant with an exercise price of $7.00 per share. We recorded $92,000 as the estimated fair value of the warrants as deferred debt issuance costs, with a corresponding increase in additional paid-in-capital.

In April 2006, we issued 30,000 warrants to a former director in exchange for expired options for services rendered. These warrants vest one year from the date of grant with an exercise price of $5.50 per share related to 20,000 warrants, and $7.50 per share related to 10,000 warrants. We recorded $70,000 as the estimated fair value of the warrants as stock-based compensation, with a corresponding increase in additional paid-in-capital.

One of our officers (and director) and three of our directors, in the aggregate, purchased $100,000 and a total of $1.275 million, respectively, of the Notes that were issued in March 2006. During the year ended December 31, 2006, the Company has paid interest of $8,472 and $147,194 respectively, on these Notes. In addition, an investment fund, of which one of our former directors is a consultant, purchased on behalf of it investors, $1 million of the notes. The investors were paid $86,944 in interest during the period.

Note 16 Quarterly Financial Information (Unaudited)

(In thousands, except per share data)	First	Second	Third	Fourth	Total
2006					
Revenue	$ 827	$ 703	$ 1,098	$ 1,685	$ 4,313
Operating loss	$ (1,273)	$ (1,478)	$ (1,731)	$ (3,138)	$ (7,620)
Net loss	$ (1,494)	$ (1,818)	$ (1,766)	$ (3,581)	$ (8,659)
Net loss per share basic and diluted	$ (0.20)	$ (0.24)	$ (0.24)	$ (0.48)	$ (1.16)
2005					
Revenue	$ 841	$ 715	$ 724	$ 875	$ 3,155
Operating loss	$ (189)	$ (415)	$ (2,931)	$ (1,132)	$ (4,667)
Net loss before cumulative effect of change in accounting principle	$ (230)	$ (375)	$ (2,868)	$ (1,076)	$ (4,549)
Cumulative effect of change in accounting principle				$ (76)	$ (76)
Net loss	$ (230)	$ (375)	$ (2,868)	$ (1,152)	$ (4,625)
Net loss applicable to common stockholders	$ (412)	$ (397)	$ (2,868)	$ (1,152)	$ (4,829)
Net loss per share before cumulative effect of change in accounting principle	$ (0.52)	$ (0.06)	$ (0.40)	$ (0.15)	$ (0.68)
Cumulative effect of change in accounting principle per share of common stock	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)
Net loss per share basic and diluted	$ (0.52)	$ (0.06)	$ (0.40)	$ (0.16)	$ (0.69)
2004					
Revenue	$ 399	$ 343	$ 841	$ 949	$ 2,532
Operating income (loss)	$ 8	$ (135)	$ (3)	$ (492)	$ (622)
Net income (loss)	$ 11	$ (126)	$ 13	$ (549)	$ (651)
Net loss applicable to common stockholders	$ (93)	$ (280)	$ (170)	$ (1,320)	$ (1,863)
Net loss per share basic and diluted	$ (0.06)	$ (0.17)	$ (0.11)	$ (1.65)	$ (1.33)

During the fourth quarter of 2006, the Company recorded an impairment charge of $790,000 related to the shut-in of Reno/Dilts field operations in February 2007 due to uneconomical performance. Also, during the last two quarters of 2006, increased E&P activities from acquisitions of gas properties resulted in higher G&A expenses for added personnel costs and benefits, plus additive DD&A charges and operating costs of the acquired producing properties.

During the third quarter of 2005, the Company recorded an estimated impairment charge in respect to its TOP gas gathering system of $2.372 million, and during the fourth quarter of 2005 recorded an additional $115,000 in respect to this impairment. See Note 5 Property, Equipment and Contracts. During the fourth quarter of 2005 the Company recorded a $76,000 cumulative effect of change in accounting principle. See Note 7 Asset Retirement Obligations.

F-21

Note 17 Subsequent Events

Capital Lease

On February 12, 2007, the Company entered into a 5-year lease agreement with J-W Power Company (J-W), effective January 24, 2007. Under the terms of the agreement, J-W will supply the Company with gas compression equipment and related services. The compression equipment will service the Company s gas gathering pipelines in the Powder River Basin.

The lease meets the criteria under Statement of Financial Accounting Standards 13, Accounting for Leases, for classification as a capital lease on the balance sheet of the Registrant. As a result, it is anticipated that a capital lease asset of approximately $3,000,000, which represents the estimated fair value of the property, will be recorded, as well as the related liability. In addition, a cash payment of $650,000 was made by the Company to J-W for future maintenance repairs in connection with the lease. The capital lease and prepayment will be amortized as expenses over the term of the lease. Monthly lease payments ranging from $100,000 to $150,000 will reduce the liability and also will include interest and executory (sales tax and environmental fees) expenses.

Registration of Additional Shares of PRB Energy, Inc. Common Stock

In connection with our issuance of 1,250,000 shares of common stock to two private lenders, the Company entered into a registration rights agreement (RRA). Pursuant to that agreement, if we fail to: (i) have the registration statement declared effective by the SEC on or before the date that is 150 days after December 28, 2006 (an Effectiveness Failure) or (ii) maintain the effectiveness of this registration statement while shares of common stock covered by the RRA remain unsold (a Maintenance Failure), then, unless the grace periods set forth in the RRA apply, as partial relief for the damages to any holder by any such delay in or reduction of its ability to sell the shares of common stock, the Company must pay to each holder an amount in cash equal to 1% of the aggregate purchase price (as such term is defined in the securities purchase agreement for the Debentures) allocable to such holder s securities included in this prospectus on each of the following dates: (i) the day of an Effectiveness Failure and on every 30th day thereafter until such Maintenance Failure is cured; and (ii) the initial day of a Maintenance Failure and on every 30th day thereafter until such Maintenance Failure is cured. If the Company fails to make these registration delay payments in a timely manner, the registration delay payments will bear interest at the rate of 2% per month until paid in full. The aggregate amount of registration delay payments may not exceed $750,000. The Company filed the registration statement on Form S-3 with the SEC on February 2, 2007.