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.

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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	2006 Price Range Low	2005 Price Range High	2005 Price Range 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.

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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.

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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:

- <u>E&P operating costs</u>: 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.

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

- <u>E&P Production taxes and other deductions</u>: 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.

- <u>Depreciation, depletion and amortization</u>: 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.

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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.

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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.

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)

/s/ Daniel D. Reichel
Date: March 29, 2007 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.

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

	Years Ended December 31,		
	2006	**2005**	**2004**