BERRY PETROLEUM CO
Form 10-K
March 01, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ý Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended **December 31, 2010**

Commission file number **1-9735**

BERRY PETROLEUM COMPANY

(Exact name of registrant as specified in its charter)

DELAWARE	**77-0079387**
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

1999 Broadway
Suite 3700
Denver, Colorado 80202

(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code:

(303) 999-4400

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

Title of each class	Name of each exchange on which registered
Class A Common Stock, $0.01 par value (including associated stock purchase rights)	New York 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 ý NO o

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ý 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, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ý Accelerated filer o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO ý

As of June 30, 2010, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $1,164,242,806.

As of February 11, 2011, the registrant had 51,434,804 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 11, 2011, all of which are held by an affiliate of the registrant.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's definitive Proxy Statement for its Annual Meeting of Shareholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

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Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Annual Report on Form 10-K that are not historical facts are forward-looking statements that involve risks and uncertainties. Words or forms of words such as "will," "might," "intend," "continue," "target," "expect," "achieve," "strategy," "future," "may," "could," "goal," "forecast," "anticipate," "estimate," or other comparable words or phrases, or the negative of those words, and other words of similar meaning, indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A. in this Annual Report on Form 10-K, under the heading "Risk Factors."

PART I

Item 1. Business

General

We are an independent energy company engaged in the production, development, exploitation and acquisition of crude oil and natural gas. We were incorporated in Delaware in 1985 and have been a publicly traded company since 1987. We can trace our roots in California oil production back to 1909. Since 2002, we have expanded our portfolio of assets through selective acquisitions driven by a consistent focus on properties with proved reserves and significant growth potential through low risk development. Our principal reserves and producing properties are located in California, Texas (E. Texas and the Permian), Utah (Uinta) and Colorado (Piceance).

We operate in one industry segment, which is the production, development, exploitation and acquisition of crude oil and natural gas, and all of our operations are conducted in the United States. Consequently, we currently report a single industry segment. See Item 8. Financial Statements and Supplementary Data for financial information about this industry segment. Information contained in this Annual Report on Form 10-K reflects our business during the year ended December 31, 2010 unless noted otherwise.

Restatement of Previously Issued Financial Statements

In 2009, we sold all of our interest in our properties located in the Denver-Julesburg basin (DJ). At the time of the DJ asset sale, we had designated derivative instruments as cash flow hedges from the forecasted sale of natural gas produced by the DJ assets. We determined that as a result of the sale of the DJ assets, the forecasted transactions were no longer probable of occurring. Accordingly, we discontinued hedge accounting for those hedges and the accumulated amount within Accumulated other comprehensive loss related to those derivatives was included in earnings from continuing operations. In addition, all recurring income statement impacts from the derivatives designated as hedges of future production expected from the DJ assets were classified as continuing operations. We had previously classified the realized gains on derivative instruments designated as cash flow hedges from the forecasted sales of natural gas produced by the DJ assets as part of continuing operations on the basis that our hedging program was managed for the purposes of corporate risk management and that hedge gains and losses were not indicative of individual asset performance when determining the amounts to include in discontinued operations.

However, after discussions with the staff of the Securities and Exchange Commission (SEC), we determined that such gains should have been classified as part of discontinued operations, on the basis that these hedges were documented as relating to the DJ assets to achieve cash flow hedge accounting in accordance with authoritative literature.

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The effect of correcting the classification of these gains resulted in a decrease in earnings from continuing operations of $12.7 million ($0.28 per diluted share) and $1.2 million ($0.02 per diluted share) for 2009 and 2008, respectively, with a corresponding increase in earnings and earnings per diluted share from discontinued operations, net of income taxes, for the same periods. The change in classification did not affect net earnings for 2009, 2008, or any of our previously issued financial statements, nor did it have an impact on any of our previously issued Balance Sheets, Statements of Shareholders' Equity or Statements of Cash Flows. See Note 16 to the Financial Statements.

Business Strengths

Balanced High Quality Asset Portfolio. Since 2002, we have grown our asset base and diversified our California heavy oil assets through acquisitions in the Permian, Uinta, E. Texas and Piceance that have significant growth potential. Our diverse asset base provides us with the flexibility to reallocate capital among our assets depending on fluctuations in oil and natural gas prices as well as area economics.

Long-Lived Proved Reserves with Stable Production Characteristics. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics, with a ratio of proved reserves to production of approximately 23 years.

Low-Risk Multi-Year Drilling Inventory in Established Resource Plays. Most of our drilling locations are located in proven resource plays that possess low geologic risk, leading to predictable drilling results. We have a significant inventory of primary development locations as well as heavy oil thermal opportunities.

Operational Control and Financial Flexibility. We exercise operating control over more than 97% of our assets. We generally prefer to retain operating control over our properties, allowing us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production, and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary which allows us a significant degree of flexibility to adjust the size of our capital budget. We finance our drilling budget primarily through our internally generated operating cash flows.

Experienced Management and Operational Teams. Our core team of technical staff and operating managers has broad industry experience, including experience in heavy oil thermal recovery operations and unconventional reservoir development and completion. We continue to utilize technologies and steam practices that will allow us to improve the ultimate recoveries of crude oil on our California properties.

Corporate Strategy

Our objective is to increase the value of our business through consistent growth in our production and reserves, both through the drill-bit and through acquisitions. We strive to operate our properties in an efficient manner to maximize the cash flow and earnings of our assets. The strategies to accomplish these goals include:

Maximize Production from Our Base Oil Assets. We are focused on the timely and prudent development of our large oil resource base through developmental and step-out drilling, down-spacing, well completions, remedial work and by application of enhanced oil recovery (EOR) methods and optimization technologies, as applicable.

Grow Oil Production from Our Inventory of Organic Development Projects. We have a proven track record of developing reserves through enhanced recovery projects and maximizing the efficiency of

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repeatable development projects. We plan to continue our focus on low-risk development of our existing assets rather than exploration.

Meet the Growing Demand for Steam Generation. We expect our enhanced oil development projects will require increasing quantities of natural gas for steam generation. Our E. Texas, Piceance, Uinta and Permian assets produce natural gas that offsets our consumption of natural gas utilized to generate steam used in our EOR activities.

Invest our Capital in a Disciplined Manner and Maintain a Strong Financial Position. We focus on utilizing our available capital on projects where we are likely to have success in increasing production and reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities in all commodity cycles. Our capital programs are generally developed to be fully funded through internally generated cash flows. We hedge a portion of our production and utilize long-term sales contracts to maintain a strong financial position and provide the cash flow necessary for the development of our assets.

Acquire Additional Resources with an Emphasis on Crude Oil. We have been successful in expanding operations through targeted acquisitions that meet our economic criteria with a primary focus on large repeatable oil development potential. We target acquisitions in and around our existing core areas and evaluate new core areas if assets become available that complement our existing portfolio. We will also continue to evaluate and make opportunistic acquisitions of natural gas properties that can be developed at reasonable costs.

Acquisition and Divestiture Activities

The following sets forth our significant acquisitions and divestures over the last several years:

2010 Acquisitions. In 2010, we made multiple acquisitions, each of which involved interests in properties located primarily in the Permian, for approximately $334 million.

2009 Divestitures. In 2009, we sold all of our interest in our DJ assets for approximately $140 million.

2008 Acquisitions. In 2008, we acquired interests in producing properties in Limestone and Harrison counties in E. Texas for approximately $668 million.

Properties

The following table provides information regarding our operations by area as of December 31, 2010:

Name, State	Total Net Acres	Proved Reserves (MMBOE)(1)	Proved Developed Reserves (MMBOE)	Proved Undeveloped Reserves (MMBOE)	2010 Gross Wells(2)	2010 Net Wells(2)
S. Midway, CA	3,062	57.8	47.9	9.9	59	58
N. Midway, CA	3,561	59.5	28.3	31.2	71	71
Permian, TX	19,791	33.8	4.5	29.3	26	24
Uinta, UT	107,245(3)	24.3	12.2	12.1	60	58
E. Texas	4,777	40.5	28.0	12.5	8	8
Piceance, CO	8,124	55.3	12.8	42.5	17	13
Totals	146,560	271.2	133.7	137.5	241	232

(1) MMBOE Million BOEs.

(2) Gross and net productive wells drilled during 2010.

(3) Does not include an additional 61,230 net acres that are subject to drill-to-earn agreements. Includes 7,790 net acres in Nevada.

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We currently have six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including Diatomite (N. Midway), Permian, Uinta, E. Texas and Piceance.

S. Midway We own and operate properties in the South Midway-Sunset Field in the San Joaquin Valley. Production from our properties in the South Midway-Sunset Field relies on thermal EOR methods, primarily cyclic steaming, to place steam effectively into the remaining oil column. This is our most mature thermally enhanced asset, with production from our Ethel D properties having commenced 100 years ago. In 2009, we drilled 19 horizontal wells and 18 vertical producers at the South Midway-Sunset Field. We also accelerated our continuous steam support for these horizontal wells by drilling six vertical steam injectors. In 2010, we expanded cyclic development and drilled 35 new producers, increasing production by 500 BOE/D from 2009. At Homebase and Formax, we continued our horizontal drilling program and expanded the continuous steam injection project by drilling 15 horizontal wells and 10 vertical steam injectors. In 2011, we expect to drill an additional four horizontal wells and 13 vertical injectors at Homebase and Formax. At Ethel D, our steam flood pilot was deemed economic and, as a result, we plan to drill 15 vertical producers and eight steam injectors in 2011.

In 2003, we acquired the Poso Creek properties in the San Joaquin Valley and have proceeded with a successful thermal EOR redevelopment. Average production from these properties increased from 50 BOE/D at acquisition in 2003 to 3,400 BOE/D in 2010. In 2010, we expanded the steam flood by drilling nine new producers and three new injectors. We also commissioned a new water plant to accommodate future production growth. In 2011, we will continue to expand the steam flood at Poso Creek by drilling nine producers and three steam flood injectors.

Average daily production from all S. Midway assets was approximately 11,780 BOE/D in 2010 compared to 11,430 BOE/D in 2009.

N. Midway Our N. Midway assets include Diatomite, Placerita and McKittrick. During 2009, we drilled 51 Diatomite wells and installed additional steam generation and water treating facilities. Average production in 2009 was 3,100 BOE/D. Diatomite production in 2010 averaged 2,720 BOE/D and was impacted by a suspension of drilling activity as we worked to secure permits from the California Division of Oil, Gas and Geothermal Resources (DOGGR) and conducted field optimization activities prior to resuming. Steam injection, which had been averaging over 30,000 barrels of steam per day (BSPD) earlier in the year, decreased as a result of the facility and infrastructure modifications. In September 2010, we received approval from the DOGGR for the next phase of development of our Diatomite project, and full project approval appears to be on schedule. The first rig resumed drilling in early October 2010, and a second rig was added in December 2010. Steam injection has steadily increased, and we exited 2010 at approximately 31,500 BSPD. Production from our Diatomite asset is expected to increase to 5,000 BOE/D by mid-2011 as we continue our development program and continue to increase steam injection. At McKittrick 21Z, we evaluated the performance of cyclic steam operations and found them to be economic. As a result, we plan to drill 44 McKittrick wells and expand infrastructure in 2011. We intend to focus additional capital investment in 2011 on initiating steam flood pilots at our Fairfield, Pan, USL-12, and Main Camp properties located in N. Midway. Average daily production from all N. Midway assets was approximately 5,320 BOE/D in 2010 compared to 5,480 BOE/D in 2009.

Permian In 2010, we acquired 19,791 net acres in the Wolfberry trend. We have identified over 400 drilling locations on 40-acre spacing and an additional 400 locations on 20-acre spacing. In 2010, we drilled 26 gross (24 net) wells, with 21 gross (19 net) wells coming in the second half of 2010 when we executed a three rig drilling program. In 2011, we plan to average a four rig program and drill approximately 72 gross wells. We exited 2010 at approximately 2,550 BOE/D.

Uinta In 2003, we established our initial acreage position in the Uinta, which includes the Ashley Forest area, targeting the Green River formation that produces both light oil and natural gas. We acquired the Brundage Canyon leasehold in Duchesne County in Northeastern Utah, which consists of working interests in approximately 51,000 gross acres on federal, tribal, and private leases. We have working interests in approximately 57,000 gross acres and exploratory rights in approximately 61,230 net acres in the Lake Canyon project, which is located immediately west of our Brundage Canyon producing properties. In 2010 we drilled 60 gross (58 net) wells, which included 36 gross (35 net) wells in Brundage Canyon, 20 gross (20 net) wells in Ashley Forest and four gross (three net) wells in Lake Canyon. We also participated in four non-operated Lake Canyon wells. The Lake Canyon drilling program identified a new pay interval in the Upper Wasatch that was commingled with the Green River formation, yielding encouraging results. We continue to monitor the progress of our initial water flood pilot in Brundage Canyon, which was implemented in the fourth quarter of 2009, and began injection on our second Brundage Canyon water flood pilot in the fourth quarter of 2010. The Ashley Forest Environmental Impact Study (EIS) continues to progress, and we anticipate approval in 2011. We plan to run a one rig program in the Uinta in 2011 focused toward developing areas of higher oil potential with added emphasis on the development of Lake Canyon. Our drilling inventory in the Uinta is approximately 350 locations distributed between Brundage Canyon, Ashley Forest, and Lake Canyon. Average daily production in Uinta was approximately 5,350 BOE/D in 2010 compared to 4,930 BOE/D in 2009.

E. Texas In 2008, we acquired certain interests in natural gas producing properties on approximately 4,500 net acres in Limestone and Harrison Counties in E. Texas. The Limestone County assets include seven productive horizons in the Cotton Valley and Bossier sands at depths between 8,000 and 13,000 feet. Additional potential exists in the Haynesville/Bossier shale. The Harrison County assets include five productive sands as well as the Haynesville/Bossier Shale, with average depths between 6,500 and 13,000 feet. We recently completed an eight well Haynesville horizontal development program. We have deferred drilling in E. Texas during 2011 while we focus on higher return oil development opportunities at our other properties. Average daily production from the E. Texas assets averaged 31 MMcf/D in 2010 as compared to 24 MMcf/D in 2009.

Piceance In 2006, we acquired two properties in the Piceance targeting the Williams Fork section of the Mesaverde formation. We have a 62.5% working interest in 6,300 gross acres on our Garden Gulch property, a working interest of 95% in 4,300 gross acres and a 5% non-operating working interest in 90 wells on our North Parachute property. We have accumulated a sizable resource base, which should allow us to add significant proved reserves as we develop these assets. We have successfully drilled 111 gross wells (69 net) at Garden Gulch and 33 gross wells (31 net) on the North Parachute property since the acquisitions of those properties. During 2009, we began a 20 well completion program testing new completion designs and saw improved well performance in line with our expectations. We continue to utilize the improved completion techniques, and results continue to meet our expectations. In January 2011, we renegotiated the agreement covering the North Parachute property such that we have until January 31, 2020 to complete our drilling obligations. See Note 10 to the Financial Statements. In 2010, we continued to develop the Garden Gulch and North Parachute properties through a one rig drilling program. Average daily production in the Piceance has increased from 4 MMcf/D in 2006 to 23 MMcf/D in 2010.

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Oil and Gas Reserves

The following table summarizes our estimated quantities of proved reserves as of December 31, 2010 based on the unweighted arithmetic average of the first-day-of the month prices during the 12-month period prior to December 31, 2010.

	Estimated Proved Reserves		
	Oil (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Developed	88,917	268,566	133,678
Undeveloped	77,264	361,626	137,535
Total proved December 31, 2010	166,181	630,192	271,213

At December 31, 2010, our proved undeveloped reserves were 137.5 MMBOE. At December 31, 2009, our proved undeveloped reserves were 109.8 MMBOE. During 2010, approximately 9 MMBOE or 8% of our December 31, 2009 proved undeveloped reserves were converted into proved developed reserves from the investment of approximately $111 million of drilling, completion and facilities capital. Our proved reserves in 2010 were impacted by certain regulatory and permitting delays in our Diatomite asset in Kern County, California and by the acquisition of several properties in the Permian. We invested significant infrastructure capital in the Diatomite asset even though drilling was curtailed until the fourth quarter, which reduced the conversion of proved undeveloped reserves from this asset. The Permian properties were largely undeveloped and approximately 26 MMBOE were added to the proved undeveloped reserves category due to these acquisitions. Drilling and completion activities primarily related to our California and Permian assets, along with engineering revisions, added approximately 15 MMBOE to proved undeveloped reserves, and 5 MMBOE were removed from this category due to performance and as a result of our future development plans. We intend to grow our production and cash flow over the next several years from an increase in capital spending that will facilitate a larger conversion of proved undeveloped reserves. We intend to convert the proved undeveloped reserves recorded as of December 31, 2010 to proved developed reserves within five years of the date the reserves were initially recorded.

Preparation of Reserves Estimates

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserve engineering is a process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition to the physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, economic factors such as changes in commodity prices or development and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates. See Part I, Item 1A "Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

All of our oil and natural gas reserves are located in the U.S. We engaged DeGolyer and MacNaughton (D&M) to prepare all of our proved oil and gas reserve estimates and the estimated future net revenue to be derived from our properties. D&M is an independent petroleum engineering consulting firm that has provided consulting services throughout the world for over 70 years. The independent engineers' estimates were prepared by the use of standard geological and engineering methods generally recognized by the petroleum industry. Reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of the 12-month average price for oil and natural gas calculated as the un-weighted arithmetic average of the first-day-of-the-month

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price for each month within the 12-month period prior to the end of the reporting period and year-end costs. The proved reserve estimates represent our net revenue interest in our properties. When preparing our reserve estimates, the independent engineers did not independently verify the accuracy and completeness of information and data furnished by us with respect to property interests, production from such properties, current costs of operation and development, current prices for production agreements relating to current and future operations and sale of production, and various other information and data. See Exhibit 99.3 Report of DeGolyer and MacNaughton dated February 15, 2011.

Reserves are also calculated internally and compared to the reserve estimates received from D&M. When compared on a field-by-field basis, some of our internally generated estimates of net proved reserves were greater and some were less than the estimates prepared by D&M. If a variance of greater than 10% occurs at the field level, it may suggest that a difference in methodology or evaluation techniques exist between us and the independent engineers. Those differences are investigated and discussed with the independent engineers to confirm that the proper methodologies and techniques were applied in the estimated reserves for these fields. There was no material difference, in the aggregate, between our internal estimates of estimated net proved reserves and the estimates prepared by D&M.

Our senior evaluation engineer oversees the reserve estimation process. He holds a Bachelor of Science degree in Mechanical Engineering from Texas A&M University and has over thirty years of petroleum engineering experience in oil and gas exploration, production, and reserve determination. The majority of his time in the industry has been spent in reserve analysis and evaluation. He has performed economic evaluations in all of the areas in which we operate and has supervised operations in a majority of them. Our reserves are also subject to multiple levels of management review.

Production, Average Sales Prices and Production Costs

The following table reflects our production, average sales price and production cost information for the years ended December 31, 2010, 2009 and 2008:

	Net Production Volumes(1)		Average Sales Price(2)		Average Operating Cost
	Crude Oil (BOE/D)	Natural Gas (Mcf/D)	Crude Oil ($/BOE)	Natural Gas (Mcf)	$/BOE
Year Ended December 31, 2010					
Total production Continuing operations	21,713	65,720	$ 67.61	$ 4.37	$ 15.95
Diatomite(3)	2,721		75.03		32.08
South Midway Sunset(4)	6,889		63.96		12.77
Piceance(3)	62	22,681	64.14	4.25	8.94
Year Ended December 31, 2009					
Total production Continuing operations	19,688	57,484	50.73	3.61	14.66
Diatomite	3,093		57.00		21.98
South Midway Sunset	7,214		48.68		10.18
Piceance	43	18,981	45.56	3.35	9.05
Year Ended December 31, 2008					
Total production Continuing operations	20,330	50,064	86.90	6.91	17.99
Diatomite	1,843		91.72		32.52
South Midway Sunset	7,790		85.60		13.88
Piceance	58	20,700	$ 68.64	$ 6.76	$ 11.78

(1) Net production represents that owned by us and produced to our interests.

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(2) Excludes all effects of derivatives. Please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information regarding the effect of derivatives on our average realized price.

(3) The Piceance and Diatomite, each of which is considered a single field, contain 15% or more of our total proved reserves.

(4) Includes Homebase and Formax.

Productive Wells and Acreage

As of December 31, 2010, we had working interests in 3,568 gross (3,485 net) active producing oil wells and 437 gross (285 net) active producing gas wells.

The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2010:

	Developed Acres(1)		Undeveloped Acres(2)		Total	
	Gross(3)	Net(3)	Gross(3)	Net(3)	Gross(3)	Net(3)
California	5,955	5,930	693	693	6,648	6,623
Colorado	2,480	1,107	9,122	7,017	11,602	8,124
Nevada	680	666	7,270	7,124	7,950	7,790
Texas	7,520	6,828	21,270	17,740	28,790	24,568
Utah(4)	20,480	19,836	125,214	79,619	145,694	99,455
Wyoming	3,880	616	1,237	196	5,117	812
Kansas			62,939	61,519	62,939	61,519
Other	40	4			40	4
Total	41,035	34,987	227,745	173,908	268,780	208,895

(1) Developed acres are acres spaced or assigned to productive wells.

(2) The undeveloped acreage subject to expiration in each of the next three years is not material.

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

(4) Does not include an additional 61,230 net acres that are subject to drill-to-earn agreements.

Drilling Activity

The following table sets forth our drilling activities for the years ended December 31, 2010, 2009 and 2008:

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development wells drilled:						
Productive	241	232	132	132	443	374
Dry(1)			2	2		
Exploratory wells drilled:						
Productive					3	2
Dry(1)	1	1			6	5
Total wells drilled:						

Productive	241	232	132	132	446	376
Dry(1)(2)	1	1	2	2	6	5

(1)
A dry well is a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

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(2) We achieved a gross drilling success rate of 99.6%, 98.5% and 98.7% for the years ended December 31, 2010, 2009 and 2008, respectively.

As of December 31, 2010, we had 7 rigs drilling on our properties and we had 7 gross (6 net) wells in progress.

Company owned drilling rigs

We own three drilling rigs. Owning these rigs allows us to meet a portion of our drilling needs in Uinta and the Piceance. Two of these rigs are not currently drilling, and one rig is drilling in the Uinta. We continue to evaluate the ownership of these rigs as the rig market and our rig requirements change.

Marketing and Customers

We market the majority of the natural gas and oil production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to a variety of purchasers under oil and gas purchase contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. The majority of our sales are to marketing companies or refiners. We typically sell production to a relatively small number of customers. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition, results of operations, or operating cash flows.

Our oil production is collected in tanks and sold via pipeline or truck. Our oil contracts are priced either on local area oil postings or are based upon the NYMEX WTI, with location or transportation differentials. A substantial portion of our oil reserves are located in California, and approximately 52% of our production is attributable to heavy crude (generally 21 degree API gravity crude oil or lower). The market price for California crude differs from the established market indices in the U.S., due principally to the higher refining costs associated with heavy crude. As of December 31, 2010, we have over 88% of our California oil production under contract with Shell Trading (US) Company and ExxonMobil Oil Corporation through March and November 2011, respectively. The remaining California production is under contract through December 2012 with a niche refiner in the Los Angeles basin.

In Utah, we are a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum of 5,000 Bbl/D of Uinta black wax crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of NYMEX WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for our 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for our crude oil. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of our crude oil sales customer in Utah could impact the marketability of a portion of our Utah crude oil volumes. Gross oil production from our Uinta properties averaged approximately 3,300 Bbl/D in 2010.

Our natural gas is transported through our own and third party gathering systems and pipelines. We incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped and the fee charged by the third-party processor or transporter. In certain instances, we enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our gas volumes. Our Rocky Mountain natural gas production is tied to the eastern markets in Lebanon, Ohio, while our Utah gas production is generally priced relative to a Rocky Mountain Northwest Pipeline (NWPL) or Questar index price. Our E. Texas natural gas is generally priced off the Florida Zone 1 or the Natural Gas Pipeline Co. of America-Texok zone (NGPL Texok) index. Permian natural gas prices are generally tied to the El Paso Permian index.

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In our producing areas, we have firm transportation contracts on interstate and intrastate pipelines to assure the delivery of our gas to market. At the time we entered into these commitments, we estimated that our production and the production of joint interest owners that we market, would be sufficient to meet these commitments. In California, we have firm transportation contracts to assure our ability to purchase a portion of our consumed gas outside of the California markets. The following table sets forth information about material long-term firm transportation contracts for pipeline capacity, which typically require a demand charge.

Pipeline	From	To	Quantity (Avg. MMBtu/D)	Term	December 31, 2010 demand charge per MMBtu	Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ 0.583	$ 5,968
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 2/2018	1.134(1)	74,216
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	1/2008 to 1/2018	1.094(1)	28,306
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,500	9/2003 to 4/2012	0.174	211
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,859	9/2003 to 9/2012	0.174	318
Questar Pipeline	Brundage Canyon, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.257	5,553
Enbridge Pipeline	Limestone and Harrison Counties, TX	Orange, TX	Up to 55,000	4/2009 to 3/2012	0.22	1,597
Total			112,359			$ 116,169

(1) Base cost per MMBtu is a weighted average cost.

We have signed firm transportation service agreements with El Paso Corporation for an average total of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. The project is expected to be in service in mid-2011.

Steaming Operations

Our California assets consist of heavy crude oil which requires heat, supplied in the form of steam, injected into the oil producing formations to reduce the oil viscosity, thereby allowing the oil to flow to the wellbore for production. We utilize cyclic steam and/or steam flood recovery methods on all assets.

Cogeneration Steam Supply. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility, are located in S. Midway. We also own a 42 MW cogeneration facility which is located in Placerita. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine that would otherwise be wasted, to produce steam. This increases the efficiency of the combined process and consumes less fuel than would be required to produce the steam and electricity separately.

Conventional Steam Generation. In addition to these cogeneration plants, we own 30 fully permitted conventional steam generators. The quantity of generators operated at any point in time is dependent on (i) the steam volume required for us to achieve our targeted production and (ii) the price of natural gas compared to the realized price of crude oil sold. In 2010, we added four additional steam generators for use in our ongoing development of the Diatomite. In 2009, we added one additional 5,000 BSPD generator at Poso Creek and three additional 5,000 BSPD generators on our Diatomite producing properties.

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Ownership of these varied steam generation facilities and sources allows for maximum operational control over the steam supply, location, and to some extent, over the aggregated cost of steam generation. Our steam supply and flexibility are crucial for the maximization of California thermally enhanced heavy oil production, cost control and ultimate oil recovery.

Total barrels of steam per day (BSPD) capacity as of December 31, 2010 are as follows:

Steam generation capacity of conventional steam generators	113,208
Steam generation capacity of cogeneration plants	42,789
Additional steam purchased under contract with a third party	1,957
Total steam capacity	157,954

The average gross volume of steam injected for the years ended December 31, 2010 and 2009 was 116,956 BSPD and 109,153 BSPD, respectively.

During December 2010, approximately 77% of the volume of natural gas purchased to generate steam and electricity was based upon California indices. We pay distribution/transportation charges for the delivery of gas to our various locations where we consume gas for steam generation purposes. However, in some cases, this transportation cost is embedded in the price of gas. Approximately 23% of supply volume is purchased in the Rockies and moved to the Midway-Sunset field using our firm transportation capacity on the Kern River Pipeline. This gas is generally purchased based upon the NWPL index.

	2010	2009	2008
Average SoCal Border Monthly Index Price per MMBtu	$ 4.34	$ 3.59	$ 7.92
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	3.94	3.09	6.25
Average PG&E Citygate Monthly Index Price per MMBtu	4.66	4.17	8.63

We are a net seller of natural gas and benefit operationally when natural gas prices increase. However, our consumption of natural gas provides a form of natural hedge as our revenues received from natural gas sales are partially offset by operating cost increases in California when natural gas prices rise. The following table shows our average 2010 and estimated average 2011 amount of production in excess of consumption and hedged volumes (in average MMBtu/D):

	2010	Estimated 2011
Approximate natural gas volumes produced in operations	65,720	70,500
Approximate natural gas consumed:		
Cogeneration operations	27,083	25,500
Conventional steam generators	27,108	40,500
Total natural gas volumes consumed in operations	54,191	66,000
Less: Our estimate of approximate natural gas volumes consumed to produce electricity(1)	(18,171)	(17,000)
Total approximate natural gas volumes consumed to produce steam	36,020	49,000
Natural gas volumes hedged	19,000	15,000
Amount of natural gas volumes produced in excess of volumes consumed to produce steam and volumes hedged	10,700	6,500

(1) We estimate this volume based on the historical allocation of fuel costs to electricity.

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Electricity

Generation. The total annual average electrical generation of our three cogeneration facilities is approximately 93 MW, of which we consume approximately 8 MW for use in our operations. Each facility is centrally located on certain of our oil producing properties. Thus the steam generated by each facility is capable of being delivered to numerous wells that require steam for the EOR process. Our investment in our cogeneration facilities has been for the express purpose of lowering the steam costs in our heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam generators. Cogeneration costs are allocated between electricity generation and oil and gas operations based on the conversion efficiency (of fuel to electricity and steam) of each cogeneration facility and certain direct costs to produce steam. Cogeneration costs allocated to electricity will vary based on, among other factors, the thermal efficiency of our cogeneration plants, the price of natural gas used for fuel in generating electricity and steam, and the terms of our power contracts. Although we account for cogeneration costs as described above, economically we view any profit or loss from the generation of electricity as a decrease or increase, respectively, to our total cost of producing heavy oil in California. Depreciation, depletion and amortization (DD&A) related to our cogeneration facilities is allocated between electricity operations and oil and gas operations using a similar allocation method.

Sales Contracts. We sell electricity produced by our cogeneration facilities to two California public utilities: Southern California Edison Company (Edison) and Pacific Gas and Electric Company (PG&E), under long-term contracts approved by the California Public Utilities Commission (CPUC). These contracts are referred to as standard offer (SO) contracts under which we are paid an energy payment that reflects the utility's Short Run Avoided Cost (SRAC) of energy plus a capacity payment that reflects a recovery of capital expenditures that would otherwise have been made by the utility. During most periods, natural gas is the marginal fuel for California utilities, so this formula provides a hedge against our cost of gas to produce electricity and steam in our cogeneration facilities. On September 20, 2007, the CPUC issued a decision (SRAC Decision) that changes the way SRAC energy prices will be determined for existing and new SO contracts and revises the capacity prices paid under current SO1 contracts. The revised pricing ordered in the SRAC Decision became effective on August 1, 2009. Certain elements of the revised pricing have not been resolved in legal and regulatory proceedings. It has not been determined whether the revised SRAC pricing will be applied retroactively, and if so, for what period. All pending legal and regulatory challenges are being held in abeyance pending final effectiveness of a global settlement approved by the CPUC in December 2010 but still subject to certain conditions precedent (Global Settlement). We do not expect the prospective reduction in electricity revenue as a result of lower SRAC prices to be material to us.

In December 2004, we executed a five-year SO1 contract with Edison for the Placerita Unit 2 facility, and five-year SO1 contracts with PG&E for the Cogen 18 and Cogen 38 facilities, each effective January 1, 2005. Our SO2 contract with Edison for the Placerita Unit 1 Facility expired on March 25, 2009. Effective upon their scheduled terminations, each of the four contracts was extended pursuant to the SRAC Decision. On December 21, 2010, we executed agreements with PG&E, which extend the electricity sales contracts for our 18 MW and 38 MW facilities until December 31, 2011. These contracts could also terminate earlier upon CPUC approval of replacement contracts, or under certain other limited circumstances. Our electricity sales contracts with Edison for our Placerita facility will continue in effect until the CPUC approves and makes available replacement SO contracts, which, under the Global Settlement, will likely be sometime in 2011; however, our current contracts could terminate earlier under certain limited circumstances. The payment provisions of the extension agreements reflect the payment provisions ordered in the SRAC Decision.

Upon Edison and PG&E's challenge in the California Court of Appeals of the legality of the CPUC decision that ordered the utilities to enter into these SO contracts, the court ruled that the

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CPUC had the right to order the utilities to execute these contracts and that the CPUC was obligated to review the prices paid under the contracts and to adjust the prices retroactively to the extent it was later determined that such prices did not comply with certain requirements. A CPUC proceeding to resolve this retroactive price issue is being held in abeyance pending the outcome of the Global Settlement. We intend to enter into new SO contracts with Edison and PG&E for all of these facilities as soon as the ongoing challenges are resolved and the CPUC has approved the terms of new SO contracts. See Item 1A. Risk Factors "The future of the electricity market in California is uncertain."

Facility and Contract Summary

Location and Facility	Type of Contract	Purchaser	Contract Expiration	Approximate Megawatts Available for Sale	Approximate Megawatts Consumed in Operations	Approximate Barrels of Steam Per Day
Placerita						
Placerita Unit 1	SO2	Edison	(1)	20		6,500
Placerita Unit 2	SO1	Edison	(1)	17	4	6,500
S. Midway						
Cogen 18	SO1	PG&E	Dec-11(2)	11	4	6,400
Cogen 38	SO1	PG&E	Dec-11(2)	37		18,000

(1) The term of this agreement was extended until the CPUC approves a replacement contract.

(2) This agreement was extended until December 31, 2011, but could terminate earlier upon CPUC approval of replacement contracts.

Competition

The oil and gas industry is highly competitive. As an independent producer, we have little control over the price we receive for our crude oil and natural gas. As such, higher costs, fees and taxes assessed at the producer level cannot necessarily be passed on to our customers. In acquisition activities, competition is intense as integrated and independent companies and individual producers are active bidders for desirable oil and gas properties and prospective acreage. Although many of these competitors have greater financial and other resources than we have, we are in a position to compete effectively due to our business strengths.

Title to Properties

Prior to the time we acquire undeveloped properties, we conduct a title investigation consistent with industry custom and practice. Most developed properties we acquire have existing title opinions. In addition, prior to commencement of drilling operations we obtain a drilling title opinion which, in the event production is achieved, is supplemented with a division order title opinion or its equivalent. To date, we have obtained or commissioned title opinions on virtually all of our producing properties and have satisfactory title to those properties in accordance with industry standards. A majority of our oil and gas properties are subject to a mortgage or deed of trust under our second amended and restated senior secured revolving credit facility (Credit Agreement), as well as to customary royalty interests, liens incidental to operating agreements, tax liens, and other minor burdens, encumbrances, easements and restrictions which do not materially interfere with the use of or affect the value of such properties.

Employees

As of December 31, 2010, we had 270 full-time employees. We also contract for the services of independent consultants involved with land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by a collective bargaining agreement. Our relations with our employees are good.

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Offices

Our corporate headquarters are located in Denver, Colorado, and we have regional offices in Bakersfield, California, Plano, Texas and Midland, Texas.

Available Information

Our website, located at http://www.bry.com, can be used to access recent news releases and Securities and Exchange Commission (SEC) filings, crude oil price postings, hedging summaries, our Annual Report, Proxy Statement, Board committee charters, Corporate Governance Guidelines, code of business conduct and ethics, the code of ethics for senior financial officers, and other items of interest. Information on our website is not incorporated into this report. SEC filings, including supplemental schedules and exhibits, can also be accessed free of charge through the SEC website at http://www.sec.gov.

Environmental and Other Regulations

We are committed to responsible management of the environment and prudent health and safety policies, as these areas relate to our operations. We strive to achieve the long-term goal of sustainable development within the framework of sound environmental, health and safety practices and standards. We strive to make environmental, health and safety protection an integral part of all business activities, from the acquisition and management of our resources to the decommissioning and reclamation of our wells and facilities.

We have programs in place to identify and manage known risks, to train employees in the proper performance of their duties and to incorporate viable new technologies into our operations. The costs incurred to ensure compliance with environmental, health and safety laws and other regulations are normal operating expenses and are not material to our operating costs. There can be no assurances, however, that changes in, or additions to, laws and regulations regarding the protection of the environment will not have an impact in the future. We maintain insurance coverage that is customary in the industry although we are not fully insured against all environmental or other risks.

Environmental Regulation. Our oil and gas exploration, production and related operations are subject to numerous and frequently changing federal, state, tribal and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Environmental laws and regulations may require the acquisition of certain permits prior to or in connection with activities or other operations, restrict or prohibit the types, quantities and concentration of substances that can be released into the environment including releases in connection with drilling and production, restrict or prohibit drilling activities or other operations that could impact wetlands, endangered or threatened species or other protected areas or natural resources, require remedial action to mitigate pollution from ongoing or former operations, such as cleanup of environmental contamination, pit cleanups and plugging of abandoned wells, and impose substantial liabilities for pollution resulting from our operations. See Item 1A Risk Factors "We are subject to existing and pending laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business."

Regulation of Oil and Gas. The oil and gas industry, including our operations, is extensively regulated by numerous federal, state and local authorities and, with respect to tribal lands, Native American tribes. These types of regulations include requiring permits for the drilling of wells, the posting of drilling bonds and the reports concerning operations. Regulations may also govern the location of wells, the method of drilling and casing wells, the rates of production or "allowables," the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the notifying of surface owners and other third parties. Certain laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. We are also subject to various laws and regulations pertaining to Native American tribal surface ownership, to Native American oil and gas leases and other exploration agreements, fees, taxes, or other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations.

Federal Energy Regulation. The enactment of the Public Utilities Regulatory Policy Act, 1978 (PURPA), as amended, and the adoption of regulations there under by the Federal Energy Regulatory Commission (FERC) provided incentives for the development of cogeneration facilities such as ours. A domestic electricity generating project must be a Qualifying Facility (QF) under FERC regulations in order to benefit from certain rate and regulatory incentives provided by PURPA.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal and state regulations that control the financial structure of an electricity generating plant and the prices and terms on which electricity may be sold by the plant. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost and that the utility sell back-up power to the QF on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The Energy Policy Act of 2005 amended PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if FERC determines that a competitive wholesale electricity market is available to QFs in the service territory. While such a determination has not been made for our service areas in California, as part of the Global Settlement, the utilities will be relieved from this obligation precedent to the global settlement. Under the Global Settlement, the utilities will be obligated to continue offering SO contracts to QFs such as us. This amendment does not affect any of our current SO contracts.

State Energy Regulation. The CPUC has broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in California and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility's cost structure (generally reflected in its retail rates), power sales agreements with independent electricity producers, such as us, are potentially under the regulatory purview of the CPUC and in particular the process by which the utility has entered into the power sales agreements. While we are not subject to regulation by the CPUC, the CPUC's implementation of PURPA is important to us, as is other regulatory oversight provided by the CPUC to the electricity market in California.

Item 1A. Risk Factors

Other Factors Affecting Our Business and Financial Results

Oil and natural gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, financial condition, results of operations and operating cash flow. Our revenues, profitability and future growth and reserve calculations depend substantially on the price received for our oil and natural gas production. These prices also affect the amount of our cash flow available for capital expenditures, working capital, payments on our various debt instruments, dividends paid on our capital stock and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can produce economically. The oil and natural gas markets fluctuate widely, and we cannot predict future oil and natural gas prices. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- regional, domestic and foreign supply and perceptions of supply of and demand for oil and natural gas;
- level of consumer demand;
- weather conditions;
- overall domestic and global political and economic conditions;
- technological advances affecting energy consumption and supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the capacity, cost and availability of oil and natural gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

- reduce the amount of cash flow available to make capital expenditures or make acquisitions;
- reduce the number of our drilling locations;
- increase the likelihood of refinery defaults;
- negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically; and
- limit our ability to borrow money or raise additional capital.

Our heavy crude oil in California may be less economic than lighter crude oil. As of December 31, 2010, approximately 43% of our proved reserves, or 117.3 million barrels, consisted of heavy oil, and light crude oil represented 18% of our proved reserves. Heavy crude oil historically sells for a discount to light crude oil, as more complex refining equipment is required to convert heavy oil into high value products. Additionally, most of our crude oil in California is produced using steam injection. This process is generally more costly than primary and secondary recovery methods.

Purchasers of our crude oil and natural gas may become insolvent. We have significant concentrations of credit risk with the purchasers of our crude oil and natural gas. For example, all of our crude oil in Utah is sold under a long-term contract to a single refiner. Under the standard credit terms with our refiners, we may not know that a refiner will be unable to make payment to us until 50 days of our production has been delivered to them. If our purchasers become insolvent, we may not be able to collect any of the amounts owed to us. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of our crude oil sales customer in Utah could impact the marketability of a portion of our Utah crude oil volumes.

Our financial counterparties may be unable to satisfy their obligations. We rely on financial institutions to fund their obligations under our Credit Agreement and make payments to us under our hedging agreements. If one or more of our financial counterparties becomes insolvent, they may not be able to meet their commitment to fund future borrowings under our credit facility which would reduce our liquidity. Additionally, at current commodity prices, a portion of our cash flow over the next three years will come from payments from our counterparties on our commodity hedging contracts. If our counterparties are not able to make these payments, our cash flow will be reduced. Recently adopted financial reform legislation may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

A widening of commodity differentials may adversely impact our revenues and our economics. Our crude oil and natural gas are priced in the local markets where the production occurs based on local or regional supply and demand factors. The prices that we receive for our crude oil and natural gas production are generally lower than the relevant benchmark prices, such as NYMEX or Brent, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential. We may not be able to accurately predict crude oil and natural gas differentials.

Price differentials may widen in the future. Numerous factors may influence local pricing, such as refinery capacity, pipeline takeaway capacity and specifications, localized storage capacity, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products we sell. Our oil and natural gas hedges are generally based on West Texas intermediate (WTI) or natural gas index prices, so we may be subject to basis risk if the differential on the products we sell widens from those benchmarks and we do not have a contract tied to those benchmarks. Additionally, regional capacity and storage issues may cause benchmark prices to become disconnected from other sources of global crude oil and natural gas which may adversely affect the effectiveness of our hedges that are based on such indices. Insufficient pipeline capacity, storage capacity or trucking capability and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and natural gas producing areas. Increases in the differential between benchmark prices for oil and natural gas and the wellhead price we receive could adversely affect our financial condition, results of operation, and operating cash flows.

Market conditions or operational impediments may hinder our access to crude oil and natural gas markets or delay our production. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities, trucking capability and refineries owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of oil and natural gas pipelines, gathering system capacity, processing facilities or refineries. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market.

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next several years are uncertain and there is no assurance that we will be able to consistently meet the minimum required volume under our refining contract relating to our production from these properties. During the term of the contract, the minimum number of delivered barrels is 5,000 BOE/D. In the event that we cannot produce the necessary volume, we may need to purchase crude to meet our contract requirements. Gross oil production from our Uinta properties averaged approximately 3,300 BOE/D during 2010.

We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly. We are dependent on several cogeneration facilities that, combined, provide approximately 27% of our steam capacity as of December 31, 2010. These facilities are dependent on

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reasonable contracts for the sale of electricity. If, for any reason, including if utilities that purchase electricity from us are no longer required by regulation to enter into electricity sales contracts with us, we were unable to enter into new or replacement contracts or were to lose any existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment may adversely affect our production, capital outlays and cash provided by operating activities. We executed agreements with Pacific Gas and Electric Company (PG&E), which extend the electricity sales contracts for our 18 MW and 38 MW facilities until December 31, 2011. These contracts could also terminate earlier upon CPUC approval of replacement contracts, or under certain other limited circumstances. Our electricity sales contracts with Southern California Edison Company (Edison) for our Placerita facility will continue in effect until the CPUC approves and makes available replacement standard form QF contracts, which, under the pending Global Settlement, will likely be sometime in 2011; however, our current contracts could terminate earlier under certain limited circumstances.

The future of the electricity market in California is uncertain. We utilize cogeneration plants in California to generate lower cost steam compared to conventional steam generation methods. Electricity produced by our cogeneration plants is sold to utilities and the steam costs are allocated to our oil and natural gas operations. We executed agreements with PG&E, which extend the electricity sales contracts for our 18 MW and 38 MW facilities until December 31, 2011. These contracts could also terminate earlier upon CPUC approval of replacement contracts, or under certain other limited circumstances. Our electricity sales contracts with Edison for our Placerita facility will continue in effect until the CPUC approves and makes available replacement standard form QF contracts, which, under the pending Global Settlement, will likely be sometime in 2011; however, our current contracts could terminate earlier under certain limited circumstances. Additionally, legal and regulatory decisions (especially related to the pricing of electricity under the contracts such as the SRAC Decision and the pending issues as to effective dates on retroactivity), can by reducing our electricity revenues adversely affect the economics of our cogeneration facilities and as a result the cost of steam for use in our oil and natural gas operations. In addition, any final determination by the CPUC to apply the SRAC pricing formula, which became effective on August 1, 2009 retroactively, so as to require payment on a one-time basis, could have a material adverse effect on our financial condition, results of operations, and operating cash flows. During the California energy crisis in 2000 and 2001, we had electricity sales contracts with PG&E and Edison, and a portion of the electricity prices paid to us under such contracts from December 2000 to March 27, 2001 has been under a degree of legal challenge since that time. There are ongoing proceedings before the CPUC in which Edison and PG&E are seeking credit against future payments they are to make for electricity purchases based on retroactive adjustments to pricing under contracts with us. It is possible that we may have a liability pending the final outcome of the CPUC proceedings on the matter. Whether or not retroactive adjustments will be ordered, how such adjustments would be calculated and what period they would cover are too uncertain to estimate at this time. On December 21, 2010, the CPUC issued an order that approves a Global Settlement by and between the three California utilities, two consumer representative groups and three parties that represent the interests of the majority of the cogeneration facilities in the state, including us, which upon its effectiveness would extinguish all pending claims of retroactive payment liability, would make available long-term standard form QF contracts and would prospectively revise SRAC pricing. Before this Global Settlement can become effective however, it must survive certain regulatory and/or legal challenges, and the FERC must grant a forthcoming application by the California utilities to be relieved from the PURPA obligation.

A shortage of natural gas in California could adversely affect our business. We may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into and within

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California. We are highly dependent on sufficient volumes of natural gas necessary to use for fuel in generating steam in our heavy oil operations in California. If the required volume of natural gas for use in our operations were to be unavailable or too highly priced to produce heavy oil economically, our production could be adversely impacted. We have firm transportation to move 12,000 MMBtu/D on the Kern River Pipeline from the Rocky Mountains to Kern County, CA, which accounts for approximately one-quarter of our current requirement.

Our use of oil and natural gas price and interest rate derivative contracts involves credit risk and may limit future revenues from price increases or reduced expenses from lower interest rates, as well as result in significant fluctuations in net income and shareholders' equity. We use derivative instruments with respect to a portion of our oil and natural gas production with the objective of achieving a more predictable cash flow, and reducing our exposure to a significant decline in the price of crude oil and natural gas. From time to time we utilize interest rate derivative contracts to fix the rate on a portion of our variable rate indebtedness, as only a portion of our total indebtedness has a fixed rate and we are therefore exposed to fluctuations in interest rates. While the use of derivative instruments limits the downside risk of price declines or rising interest rates, as applicable, their use may also limit future revenues from price increases or reduced expenses from lower interest rates, as applicable. Derivative transactions also involve the risk that the counterparty may be unable to satisfy its obligations.

Our future success depends on our ability to find, develop and acquire oil and natural gas reserves. To maintain production levels, we must locate and develop or acquire new oil and natural gas reserves to replace those depleted by production. Without successful exploration, exploitation or acquisition activities, our reserves, production and revenues will decline. We may not be able to find, develop or acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and natural gas prices or operating difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under credit arrangements, we may be unable to expend the capital necessary to locate and to develop or acquire new oil and natural gas reserves.

Actual quantities of recoverable oil and natural gas reserves and future cash flows from those reserves, future production, oil and natural gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Estimating accumulations of oil and natural gas is a complex process that relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC. The accuracy of a reserve estimate is a function of:

- quality and quantity of available data;
- interpretation of that data; and
- accuracy of various mandated economic assumptions.

Any significant variance could materially affect the quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of development, changes in development schedule and exploration and prevailing oil and natural gas prices.

In accordance with SEC requirements, we base both our estimated quantities of reserves and our estimated discounted future net cash flows from our proved reserves on an un-weighted arithmetic average of the first-day-of-the month price for each month during the calendar year and on year-end

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costs. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

Future commodity price declines and/or increased capital costs may result in a write-down of our asset carrying values, which could adversely affect our results of operations and limit our ability to borrow funds. The value of our assets depend on crude oil and natural gas prices. Declines in these prices as well as increases in development costs, changes in well performance, delays in asset development or deterioration of drilling results may result in our having to make substantial downward adjustments to our estimated proved reserves, and accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments.

We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. If net capitalized costs of our oil and natural gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties annually and at any time when events or circumstances indicate a review is necessary, based on estimated prices as of the end of the reporting period. The carrying value of oil and natural gas properties is computed on a field-by-field basis. Once incurred, a write-down of oil and natural gas properties is not reversible at a later date even if oil or natural gas prices increase. While we did not incur any such impairment charges in 2009 or 2010, natural gas prices have decreased significantly below price levels at the time of the acquisition of our natural gas properties in 2006 and 2008. It is possible that further declines in commodity prices could prompt an impairment in the future, which could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our Credit Agreement.

Approximately 51% of our total estimated proved reserves at December 31, 2010 were proved undeveloped reserves and may be reclassified as unproved or may not ultimately be produced or developed. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our crude oil and natural gas reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated. The SEC generally requires that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time. Proved undeveloped reserves that are not timely developed are subject to possible reclassification as non-proved reserves. Substantial downward adjustments to our estimated proved reserves could have a material adverse effect on our financial condition, results of operations, and operating cash flows. In addition, our undeveloped reserves may not ultimately be developed or produced during the time periods we have planned, at the costs we have budgeted, or at all, which in turn may have a material adverse effect on our results of operations.

Competitive industry conditions may negatively affect our ability to conduct operations. Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and of proved undeveloped acreage. Major and independent oil and natural gas companies actively bid for desirable oil and natural gas properties, as well as for the equipment, supplies, labor and services required to operate and develop their properties. Some of these resources may be limited and have higher prices due to current strong demand. Many of our competitors have financial resources that are substantially greater than ours, which may adversely affect our ability to compete within the industry.

Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry.

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These larger companies may have a greater ability to continue drilling activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition, results of operations, and operating cash flows

Drilling is a high-risk activity. Our future success will partly depend on the success of our drilling program. In addition to the numerous operating risks described in more detail below, these drilling activities involve the risk that no commercially productive oil or natural gas reservoirs will be discovered. Also, we are often uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- obtaining government and tribal required permits;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- changes in regulations;
- compliance with governmental or landowner requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

As a result, there can be no assurance that our anticipated production levels will be realized or that our estimates of proved reserves will not be negatively impacted. For example, although we expect that our Diatomite production will increase to 5,000 BOE/D by mid-2011, actual production from these assets could be significantly lower. During the first half of 2010, Diatomite production decreased primarily due to the inability to drill new wells pending the receipt of permits from the DOGGR. Although we have received such permits, the DOGGR is expected to issue new regulations for the development of Diatomite, the effect of which we are unable to determine until such regulations are issued.

The oil and natural gas business involves many operating risks that can cause substantial losses. The oil and gas business involves many operating risks, and insurance we maintain may not protect us against all of these risks. These risks include:

- fires;
- explosions;
- blow-outs;

uncontrollable flows of oil, natural gas, formation water or drilling fluids;

natural disasters;

pipe or cement failures;

casing collapses;

embedded oilfield drilling and service tools;

abnormally pressured formations;

- major equipment failures, including cogeneration facilities; and
- environmental hazards such as oil spills, natural gas leaks, pipeline ruptures and discharges of toxic gases.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties;
- more stringent regulations applicable to our operations;
- suspension of operations; and
- repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us. In accordance with customary industry practices, we maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. For instance, we do not carry business interruption insurance. We may elect not to carry insurance if the cost of available insurance is excessive relative to the risks presented. In addition, we cannot insure fully against pollution and environmental risks. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations, and operating cash flows. While we intend to obtain and maintain insurance coverage we deem appropriate for these risks, there can be no assurance that our operations will not expose us to liabilities exceeding such insurance coverage or to liabilities not covered by insurance.

We are subject to comprehensive and stringent existing and pending laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business. Our operations are regulated extensively at the federal, state, regional and local levels by environmental laws and regulations that impose limitations on our discharge of pollutants into the environment, establish standards for our management, treatment, storage, transportation and disposal of hazardous materials and solid and hazardous wastes, and impose obligations requiring us to investigate and remediate contamination resulting from our operations. In certain circumstances, we also must satisfy federal and state requirements for providing environmental assessments, environmental impact studies and/or plans of development before we commence exploration and production activities. Environmental requirements applicable to our operations generally have become more stringent in recent years, and compliance with those requirements has become more expensive. Frequently changing environmental laws and regulations have increased our costs to plan, design, drill, install, operate and abandon oil and natural gas wells and other facilities, and may impose substantial liabilities if we fail to comply with such regulations or for any contamination resulting from our operations. Our business results from operations and financial condition, results of operations, and operating cash flows may be adversely affected by any failure to comply with, or future changes to, these laws and regulations. In particular, failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal sanctions, including the payment of monetary penalties and the performance of remedial obligations.

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From time to time we have experienced accidental spills, leaks and other discharges of contaminants at our properties. We could be liable for the investigation or remediation of such contamination, as well as claims for personal injury, property damage or natural resource damage arising from the contamination. We have incurred expenses and penalties in connection with contamination arising from our operations in the past, and we may do so in the future. Such liabilities may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate, and may arise because of our status as an owner or operator and not because of any noncompliance with applicable environmental laws. Under a number of environmental laws, including the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), such liabilities may be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. Some of the properties that we have acquired, or in which we may hold an interest but not operational control, may have past or ongoing contamination for which we may be held responsible. Some of our operations are in environmentally sensitive areas that may provide habitat for endangered or threatened species, and other protected areas, and our operations in such areas must satisfy additional regulatory requirements. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed certain drilling projects and/or access to prospective lands and have filed litigation in an attempt to overturn decisions granting the performance of such projects, including decisions made by the U.S. Bureau of Land Management regarding several leases in Utah that we have been awarded.

Climate change legislation or regulatory initiatives may adversely affect our operations, our cost structure, and the demand for the oil and natural gas that we produce. On December 15, 2009, the U.S. Environmental Protection Agency (EPA) published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public heath and the environment because emissions of such gasses are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Following issuance of this finding, the EPA adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to "best available control technology" standards for GHG that have yet to be developed. With regard to the monitoring and reporting of GHGs, on December 17, 2010, the EPA amended the "Mandatory Reporting of Greenhouse Gases" rule (Reporting Rule), originally issued in September 2009. The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gases emissions annually on a facility-by-facility basis. Further, on November 8, 2010, EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO2 equivalent per year will now be required to report annual GHG emissions to EPA, with the first report due on March 31, 2012.

Similarly, legislation has been introduced in the United States Congress that would establish measures restricting greenhouse gas emissions in the United States. At the state level, over one-half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. The State of California has adopted legislation that caps California's GHG emissions at 1990 levels by

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2020, and the California Air Resources Board (CARB) has implemented mandatory reporting regulations and is proceeding with early action measures to reduce GHG emissions prior to January 1, 2012. CARB is also developing regulations to implement a cap and trade program in 2012 to reduce GHG emissions. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Congress has, in the past, considered two companion bills for the "Fracturing Responsibility and Awareness of Chemicals Act" (the FRAC Act). While now dead, if reintroduced, the bills would repeal an exemption in the federal Safe Drinking Water Act (SWDA) for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of the FRAC Act have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. If reintroduced, the legislation would require the reporting and public disclosure of chemicals used in the fracturing process. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Further, if enacted, the FRAC Act could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any future federal or state laws or implementing regulation imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete natural gas wells in shale formations and increase our costs of compliance and doing business.

Our operations are subject to numerous federal, state and tribal regulations and laws; compliance with existing and future laws may increase our costs and delay our operations. Our activities are also subject to regulation by the federal government, oil and natural gas-producing states and one Native American tribe. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions that are more expensive than we have anticipated could have a negative effect on our ability to explore or develop our properties.

Changes to current tax laws may affect our ability to take certain deductions. Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could negatively affect our financial condition, results of operations and operating cash flow.

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Derivatives legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. New comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the Commodities Futures Trading Commission (the CFTC) to regulate certain markets for over-the-counter (OTC) derivative products. Currently, final rules to be adopted by the CFTC implementing the mandates of the new legislation are pending. Such rules would require certain derivatives to clear through clearinghouses. The effect on our business will depend in part on whether we are determined to be a major swap participant or swap dealer or a qualifying end-user, as those terms are defined in the final rules. We may be required to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities. The CFTC has proposed regulations that, if adopted, may exempt us from margin and clearing requirements, but the timing of adoption of such regulations, and their scope, is uncertain. Even if we are not deemed a major swap participant or swap dealer, the rules could impose burdens on market participants to such an extent that liquidity in the bilateral OTC derivative market decreases substantially. The legislation may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The legislation and any new regulations, including determinations with respect to the applicability of margin requirements and other trading structures, could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

Property acquisitions are a component of our growth strategy, and our failure to complete future acquisitions successfully could reduce our earnings and slow our growth. Our business strategy has emphasized growth through strategic acquisitions, but we may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. If we are unable to achieve strategic acquisitions, our growth may be impaired, thus impacting earnings, cash from operations and reserves.

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities. Our recent growth is due in part to acquisitions of properties with additional development potential and properties with minimal production at acquisition but significant growth potential, and we expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include: recoverable reserves, exploration potential, future oil and natural gas prices, operating costs, production taxes, access rights and potential environmental and other liabilities. Such assessments are inexact, and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not allow us to become sufficiently familiar with the properties, and we do not always discover structural, subsurface, environmental and access problems that may exist or arise. Our review prior to signing a definitive purchase agreement may be even more limited.

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We generally are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, on acquisitions. Often, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. If material breaches are discovered by us prior to closing, we could require adjustments to the purchase price or if the claims are significant, we or the seller may have a right to terminate the agreement. We could also fail to discover breaches or defects prior to closing and incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, for which we would have limited or no contractual remedies or insurance coverage.

There are risks in making acquisitions, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, and costs of increased scope, geographic diversity and complexity of our operations. Increasing our reserve base through acquisitions is an important part of our business strategy. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, the future prices of oil and natural gas, revenues and costs, including synergies;
- an inability to integrate successfully the properties and businesses we acquire;
- a decrease in our liquidity to the extent we use a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property or business will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

If third-party pipelines interconnected to our natural gas wells and gathering facilities become partially or fully unavailable to transport our natural gas, our financial condition, results of operations and operating cash flows could be adversely affected. We depend upon third party pipelines that provide delivery options from our wells and gathering facilities. Since we do not own or operate these pipelines, their continuing operation in their current manner is not within our control. If any of these third-party pipelines become partially or fully unavailable to transport our natural gas, or if the natural gas quality specifications for their pipelines change so as to restrict our ability to deliver natural gas to those pipelines, our revenues and cash available for distribution could be adversely affected.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase. Section 1(b) of the Natural Gas Act (NGA) exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional

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tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly, the classification and regulation of some of our natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event our gathering facilities are reclassified to FERC-regulated transmission services, we may be required to charge lower rates and our revenues could thereby be reduced.

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. FERC has issued an order requiring certain participants in the natural gas market, including natural gas gatherers and marketers, which engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. In addition, FERC has issued an order requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, to post daily certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu per day. Should we fail to comply with these requirements or any other applicable FERC-administered statute, rule, regulation or order, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

The loss of key personnel could adversely affect our business. We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business, and we do not maintain key man insurance on the lives of any of these persons. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

We may not adhere to our proposed drilling schedule. Our final determination of whether to drill any scheduled or budgeted wells will depend on a number of factors, including:

- results of our exploration efforts and the acquisition, review and analysis of our seismic data, if any;
- availability of sufficient capital resources to us and any other participants for the drilling of the prospects;
- approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability and prices of drilling rigs and crews; and
- availability of leases, license options, farm-outs, other rights to explore and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. For instance, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads. In addition, we will not necessarily drill wells on all of our identified drilling locations on our acreage.

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We may incur losses as a result of title deficiencies. We acquire from third parties, or directly from the mineral fee owners, working and revenue interests in the oil and natural gas leaseholds and estates upon which we will perform our exploration activities. The existence of a material title deficiency can reduce the value or render a property worthless, thus adversely affecting our financial condition, results of operations and operating cash flow. Title insurance covering mineral leaseholds is not always available, and when available is not always obtained. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. In cases involving material title problems, the amount paid for affected oil and natural gas leases or estates can be generally lost, and a prospect can become undrillable.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information required by Item 2. Properties is included under Item 1. Business.

Item 3. Legal Proceedings

While we are, from time to time, a party to certain lawsuits in the ordinary course of business, we do not believe any of such existing lawsuits will have a material adverse effect on our operations, financial condition, or operating cash flows.

Executive Officers

Listed below are the names, ages (as of December 31, 2010) and positions of our executive officers and their business experience during at least the past five years. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 57, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 2004, Mr. Heinemann acted as the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and as liaison between the independent directors and the CEO. Mr. Heinemann joined the Board in March of 2002. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

DAVID D. WOLF, 40, has been Executive Vice President and Chief Financial Officer since August 2008. Mr. Wolf was previously employed by JPMorgan from 1995 to 2008 where he served as a Managing Director in JPMorgan's Oil and Gas Group and advised on numerous equity, debt and M&A transactions in the energy industry.

MICHAEL DUGINSKI, 44, has been Executive Vice President and Chief Operating Officer since September 2007. Mr. Duginski served as Executive Vice President of Corporate Development and California from October 2005 to August 2007; he acted as Senior Vice President of Corporate Development from June 2004 through October 2005 and as Vice President of Corporate Development

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from February 2002 through June 2004. Mr. Duginski, a mechanical engineer, was previously employed by Texaco, Inc. from 1988 to 2002 where his positions included Director of New Business Development, Production Manager and Gas and Power Operations Manager. Mr. Duginski is also an Assistant Secretary.

GEORGE T. CRAWFORD, 50, has been Senior Vice President of California Production since May 2009. Mr. Crawford served as Vice President of California Production from October 2005 until May 2009, Vice President of Production from December 2000 through October 2005 and as Manager of Production from January 1999 to December 2000. Mr. Crawford, a petroleum engineer, previously served as the Production Engineering Supervisor for Atlantic Richfield Corp. from 1989 to 1998, with numerous engineering and operational assignments, including Production Engineering Supervisor, Planning and Evaluation Consultant and Operations Superintendent.

DAN ANDERSON, 48, has been Vice President of Rocky Mountains Production since October 2005. Mr. Anderson was Rocky Mountains Manager of Engineering from August 2003 through October 2005. Previously, Mr. Anderson, a petroleum engineer, served as a Senior Staff Petroleum Engineer with Williams Production RMT from August 2001 through August 2003. He also was a Senior Staff Engineer with Barrett Resources from October 2000 through August 2001. He previously held various engineering and management positions with Santa Fe Snyder Corporation and Conoco, Inc. from 1985 to 2000.

WALTER B. AYERS, 67, has acted as Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with the Company. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

SHAWN M. CANADAY, 35, has held the position of Vice President of Finance and Treasurer since August 2009. Mr. Canaday was Vice President and Controller from June 2008 until July 2009 and was Interim Chief Financial Officer from June 2008 until August 2008. Mr. Canaday served as Controller from February 2007 to July 2009, as Treasurer from December 2004 to February 2007 and as Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is also an Assistant Secretary.

GEORGE W. CIOTTI, 47, has held the position of Vice President, Corporate Development since January 2010. Mr. Ciotti was Manager of Business Development from January 2009 through December 2009 and Senior Financial Analyst from December 2007 until December 2008. Immediately prior to joining Berry, Mr. Ciotti was President and Founder of a consulting company focused on financial and business services. He also had ten years of experience with Texaco in positions such as Assistant Controller and Senior Project Economist.

DAVIS O. O'CONNOR, 56, has been the Vice President, General Counsel, and Secretary since October 2010. He previously served as a partner and an associate with the Denver law firm of Holland and Hart LLP since 1979 where he practiced in the areas of domestic and international business transactions including mergers, acquisitions, divestitures, joint ventures and related transactions, primarily in the oil and natural gas industry.

JAMIE L. WHEAT, 40, has held the position of Principal Accounting Officer since March 2010, and Controller since August 2009. Ms. Wheat was the Accounting Manager from August 2008 until August 2009. Prior to joining the Company, Ms. Wheat was a Senior Manager in the assurance practice group of KPMG, where she worked from 2001 to 2008.

PART II

Item 5. Market for the Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Shares of Class A Common Stock and Class B Stock are each entitled to one vote and 95% of one vote, respectively. Each share of Class B Stock is entitled to a $0.50 per share preference in the event of liquidation or dissolution. Further, each share of Class B Stock is convertible into one share of Class A Common Stock at the option of the holder.

Our Class A Common Stock is listed on the New York Stock Exchange under the symbol BRY. The Class B Stock is not publicly traded. The market data and dividends for 2010 and 2009 are shown below:

	2010			2009		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 31.27	$ 25.62	$ .075	$ 13.10	$ 5.50	$ .075
Second Quarter	34.30	25.57	.075	22.76	10.52	.075
Third Quarter	32.23	24.30	.075	28.46	14.90	.075
Fourth Quarter	44.80	30.65	.075	31.37	24.87	.075
Total Dividends Paid			$ .300			$ .300

The number of holders of record of our Class A Common Stock was 532 as of February 11, 2011. There was one Class B Shareholder of record as of February 11, 2011.

Dividends

Our regular annual dividend is currently $0.30 per share, payable quarterly in March, June, September and December.

Since our formation in 1985 through December 31, 2010, we have paid dividends on our Common Stock for 85 consecutive quarters, and previous to that for eight consecutive semi-annual periods. We intend to continue the payment of dividends, although future dividend payments will depend upon our level of earnings, operating cash flow, capital commitments, financial covenants and other relevant factors. Dividend payments are limited by covenants in our (i) Credit Agreement to the greater of $35 million or 75% of net income, and (ii) bond indentures to up to $20 million annually irrespective of our coverage ratio or net earnings if we have exhausted our restricted payments basket, and up to $10 million in the event we are in a non-payment default.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders (1)	2,017,225	$ 25.87	1,149,837
Equity compensation plans not approved by security holders			

(1) Excludes 557,473 shares of restricted stock units for which the vesting period has not lapsed.

Issuer Purchases of Equity Securities

None.

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Performance Graph

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 December 31, 2005 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index and a Peer Group, assuming reinvestment of dividends for each measurement period. The information shown is historical and is not necessarily indicative of future performance. The 14 companies which make up the "Previous Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Forest Oil Corp., Petrohawk Energy Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Range Resources Corp., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp. The 14 companies which make up the "Current Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Forest Oil Corp., Penn Virginia Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Sandridge Energy Inc., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN

Among Berry Petroleum Company, the S&P 500 Index,
the Russell 2000 Index, Previous Peer Group and Current Peer Group

	12/05	12/06	12/07	12/08	12/09	12/10
Berry Petroleum Company	100.00	109.51	158.32	27.30	107.52	162.72
S&P 500	100.00	115.80	122.16	76.96	97.33	111.99
Russell 2000	100.00	118.37	116.51	77.15	98.11	124.46
Previous Peer Group	100.00	102.42	149.00	77.99	119.52	138.98
Current Peer Group	100.00	103.48	143.19	62.59	94.88	120.62

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Item 6. Selected Financial Data

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8. Financial Statements and Supplementary Data. The financial information at December 31, 2010 and 2009 and for the years ended December 31, 2010, 2009 and 2008 was derived from the Balance Sheets, Statements of Income, and Statements of Cash Flows in the audited financial statements and the accompanying notes to those financial statements included in Item 8. Financial Statements and Supplementary Data. The financial information at December 31, 2008, 2007 and 2006 and for the years ended December 31, 2007 and 2006 was derived from unaudited financial data not included in the report. The Statements of Income Data and Operating Data for the years ended December 31, 2009, 2008, 2007 and 2006 have been restated to reflect adjustments that are further discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 16 to the Financial Statements.

	Year Ended December 31,			
	Restated	**Restated**	**Restated**	**Restated**
2010	**2009**	**2008**		