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

FORM 10-K

x Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2009**
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 x 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 x
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 x 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 x NO o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer, 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 filerx Accelerated filero Non-accelerated filero Smaller reporting companyo
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO x
As of June 30, 2009, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $684,959,425. As of February 1, 2010, the registrant had 50,952,786 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 1, 2010 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 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 on page 17 in Part I, Item 1A in this Form 10-K filed with the Securities and Exchange Commission, under the heading "Risk Factors."

PART I

Item 1. Business

General

We are an independent energy company engaged in the production, development, acquisition, exploitation of and exploration for, crude oil and natural gas. While 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. In 2003, we purchased and began operating properties in the Rocky Mountains. In 2008, we purchased and began operating properties in East Texas (E. Texas) and in 2010 we expect to enter the Permian basin in West Texas (W. Texas). Our corporate headquarters are located in Denver, Colorado and we have regional offices in Bakersfield, California and Plano, Texas. Information contained in this report on Form 10-K reflects our business during the year ended December 31, 2009 unless noted otherwise.

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.

We operate in one industry segment, which is the production, development, acquisition, exploitation of and exploration for, 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 "Financial Statements and Supplementary Data" for financial information about this industry segment.

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 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. At our mature South Midway-Sunset Field, we continue to add horizontal wells and additional steam flooding capacity to maintain and increase production levels. In addition, since we acquired our Poso Creek assets in 2003, we have successfully completed thermal EOR redevelopment to increase production from under 50 BOE/D at acquisition to average production of 3,200 BOE/D in 2009.

Grow Oil Production from our Inventory of Organic Development Projects. We have a proven track record of developing reserves through enhanced recovery projects, as well as entering into new hydrocarbon basins. For example, in our North Midway diatomite, production averaged 3,100 BOE/D in 2009 and we expect to exit 2010 at 5,000 BOE/D and continue to grow the asset significantly over the next several years. We plan to continue our focus on low-risk development of our existing assets rather than exploration.

Increase Natural Gas Production that will Meet the Growing Demand for Steam Generation. Our assets in E. Texas, Piceance and Uinta basins produce natural gas that offsets our consumption of natural gas utilized to generate steam used in our EOR activities. We intend to continue to increase production from these assets as we focus on additional enhanced oil development projects that we expect will require increasing quantities of natural gas for steam generation.

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/or 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, but we also may obtain alternative sources of capital investment to develop our assets through partnerships, joint ventures or other investment opportunities with third parties. We hedge a portion of our production and utilize long-term sales contracts whenever possible 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 in our core areas of expertise. This strategy allows us to leverage our operating and technical expertise and build on established core operations. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable oil development potential in these regions. We will also continue to evaluate natural gas properties, primarily in our core areas of operation, which can be developed at reasonable costs.

Business Strengths

Balanced High Quality Asset Portfolio. Since 2002, we have grown our asset base and diversified our California heavy oil through acquisitions in the Permian basin, Rocky Mountains and E. Texas regions that have significant growth potential. Our diverse asset base provides us with the flexibility to reallocate capital among our assets depending on fluctuations in natural gas and oil 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 21 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. Our California assets have an average depth of less than 2,000 feet and are located in areas where we are an established producer. Our E. Texas Assets provide us with the opportunity for repeatable development of multiple stacked reservoirs in the Travis Peak, Cotton Valley and Bossier sands and in the Haynesville shale. In the Permian basin we expect to begin drilling in 2010 to multiple targets including the Spraberry, Dean, Wolfcamp and Strawn formations on 40-acre spacing. Our historical drilling success rate for the three years ended December 31, 2009 averaged 99%.

Operational control and financial flexibility. We exercise operating control over more than 95% 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 have broad industry experience, including experience in heavy oil thermal recovery operations and tight gas sands 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.

Acquisition and Divestiture Activities

We pursue acquisitions that meet our criteria for investment returns and that are consistent with our corporate strategy, and seek to divest certain properties from time to time that do not fit or complement our strategic growth plan.

On January 8, 2010, we entered into an agreement to acquire certain properties primarily in the Wolfberry trend in W. Texas from a private seller for total cash consideration of $126 million. At December 31, 2009, the properties included total proved reserves of 11.2 MMBOE, of which 85% were crude oil and 23% were proved developed. We expect to close in the first quarter of 2010, subject to customary closing conditions. We have identified over 130 drilling locations on forty acre spacing in the Wolfberry trend targeting the Spraberry, Dean, Wolfcamp and Strawn formations. We plan to test twenty acre down spacing in late 2010, which would provide an additional 150 drilling locations on twenty acre spacing. We would operate approximately 70% of, and would have an average 68.5% working interest (54.1% net revenue interest) in, the properties to be acquired in the Wolfberry trend.

On April 1, 2009 we sold our DJ basin assets and related hedges for $154 million before customary closing adjustments.

On July 15, 2008, we acquired a 100% working interest in natural gas producing properties on 4,500 net acres in Limestone and Harrison counties in E. Texas for approximately $668 million, including post closing adjustments of $46 million.

In May 2007, we sold our West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million, including post closing adjustments.

Properties

The following table provides information regarding our operations by area as of December 31, 2009:

Name, State	% Average Working Interest	Total Net Acres	Proved Reserves (MMBOE) (1)	Proved Developed Reserves (MMBOE)	% of Total Proved Developed Reserves	Proved Undeveloped Reserves (MMBOE)	% of Total Proved UndevelopedReserves
S. Midway, CA	98	3,062	59.6	49.5	39%	10.1	9%
N. Midway, CA	100	2,230	52.2	26.4	21	25.8	23
Uinta, UT	98	36,636	22.9	9.8	8	13.1	12
E. Texas	99	4,508	40.0	27.3	22	12.7	12
Piceance, CO	55	3,157	60.6	12.5	10	48.1	44
Totals		49,593	235.3	125.5	100%	109.8	100%

(1) MMBOE – Million BOEs

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. Our S. Midway asset team is primarily focused on production and generates significant cash flow to fund our planned drilling inventory in our N. Midway, Piceance, E. Texas and Uinta projects.

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. We have planned a five-year, 150-well drilling program at Ethel D to develop the significant undeveloped reserves remaining on this asset. In 2008, we added 20 horizontal wells below existing horizontal wells at the South Midway-Sunset Field, and we further developed Ethel D by drilling 32 producers and initiating a pilot steam flood. In 2009 we drilled 19 horizontal wells and 18 vertical producers at the South Midway-Sunset Field. These wells have been placed deeper and closer to the oil-water contact. All of these wells are currently on production and are performing in line with expectations. We also accelerated our continuous steam support for these horizontal wells by drilling six vertical steam injectors. At Ethel D we have been encouraged by the performance of our steam flood pilots and expanded the flood in the fourth quarter of 2009. In 2010 at Homebase and Formax we will be completing our horizontal drilling program and expanding the continuous steam injection project by drilling 15 horizontal wells and 10 vertical steam injectors. Capital will also be focused on further thermal development at Ethel D by drilling 24 producers.

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 3,200 BOE/D in 2009. In 2009, we expanded the steam flood by drilling eight new injectors. To provide steam to these wells we also installed a fifth steam generator. In 2010 we will continue to expand the steam flood at Poso Creek drilling 10 producers and three steam flood injectors.

N. Midway – In 2009, total proved reserves from the N. Midway diatomite asset were 35.3 MMBOE, representing a 15% increase from 2008. In 2008, total proved reserves and production from the N. Midway diatomite asset were 30.6 MMBOE and 0.7 MMBOE, respectively, representing an increase from 2007 of 162% in proved reserves and 86% in production. We expect significant proved reserve additions from this asset. In 2008, we drilled approximately 85 diatomite wells, completed major infrastructure upgrades that will support future development, increased steam injection and further refined our thermal recovery techniques. 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. During the fourth quarter of 2009, we initiated a four-pattern steam flood pilot on our recently acquired McKittrick property. In 2010, capital will be focused on drilling an additional 100 diatomite wells, major infrastructure upgrades that will support future development, increasing steam injection, and further refining our thermal recovery techniques. In addition, capital will be invested in the initiation of four-pilot steam floods at McKittrick, N. Midway, and Placerita.

Permian – On January 8, 2010, we entered into an agreement to acquire certain properties primarily in the Wolfberry trend in W. Texas from a private seller for total cash consideration of $126 million. At December 31, 2009, we estimate that the properties included total proved reserves of 11.2 MMBOE, of which 85% were crude oil and 23% were proved developed. We expect to close in the first quarter of 2010, subject to customary closing conditions. We have identified over 130 drilling locations on forty acre spacing in the Wolfberry trend targeting the Spraberry, Dean, Wolfcamp and Strawn formations. We plan to test twenty acre down spacing in late 2010 which would provide an additional 150 drilling locations on twenty acre spacing. We would operate approximately 70% of, and would have an average 68.5% working interest (54.1% net revenue interest) in, the properties acquired in the Wolfberry trend.

Uinta – In 2003, we established our initial acreage position in the Uinta basin, targeting the Green River formation that produces both light oil and natural gas. We acquired the Brundage Canyon leasehold in Duchesne County, northeastern Utah, which consists of working interests in approximately 55,000 gross acres which include federal, tribal and private leases. In 2004, we acquired working interests in approximately 163,000 gross acres in the Lake Canyon project, which is located immediately west of our Brundage Canyon producing properties. Total production in Uinta averaged 4,929 BOE/D in 2009 compared to 6,142 BOE/D in 2008. In 2008, we drilled 51 gross (50 net) wells, which included 47 wells at Brundage Canyon, including eight Ashley Forest wells, and four Green River wells at Lake Canyon. In 2009, capital was primarily directed at facility upgrades, pursuing the remaining three Lake Canyon completions, and the Ashley Forest Environmental Impact Study (EIS). Implementation of a water flood pilot in Brundage Canyon had initial start up in the beginning of the fourth quarter of 2009. While the Ashley Forest Development EIS continues to progress with approval now expected in 2010, we obtained a category exemption for 25 wells in the Ashley Forest. In 2010, we plan to run a one rig program in the Uinta basin focused toward developing areas of higher oil potential.

E. Texas – In 2008, we acquired certain interests in natural gas producing properties in the E. Texas Cotton Valley on 4,500 net acres in Limestone and Harrison Counties for approximately $668 million in cash. The E. Texas assets established a core area in a low risk repeatable area and provided an inventory of drilling and recompletion projects. In Limestone County, we are targeting seven productive sands including the Cotton Valley and Bossier sands at depths between 8,000 and 13,000 feet. In Harrison County, we are targeting five productive sands and Haynesville Shale with average depths between 6,500 and 13,000 feet. Production from our E. Texas Assets averaged 24 MMcf/D in 2009. We currently operate a one rig program, and we began drilling our first horizontal Haynesville well in Harrison County in the fourth quarter of 2009. During 2009 we drilled 11 vertical wells in E. Texas. In 2010, we plan to run a one rig program to horizontally drill in the Haynesville Shale in Harrison County.

Piceance – We have two properties in the Piceance basin in Colorado 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 and a net operating working interest of 95% in 4,300 gross acres and a 5% non-operating working interest on 6,300 gross acres on our North Parachute Ranch property. We have accumulated a sizable resource base which should allow us to add significant proved reserves over the next several years. Total production in Piceance averaged 19 MMcf/D during 2009 and 20.8 MMcf/D in 2008. We operated a four rig drilling program for most of 2008 and drilled 54 gross (27 net) wells at Garden Gulch and 18 gross (17 net) wells at North Parachute. Significant progress was made during 2008 in reducing the days required to drill wells. By the end of 2008, the number of drilling days averaged 10 days on Garden Gulch and 11 days in North Parachute, a 40% reduction in drilling times compared to early 2008. During 2009, we began a 20 well completion program testing new completion designs and have seen encouraging results in line with our expectations. During 2009 we added water handling infrastructure which reduced our operating costs in the Piceance basin. "See Item 1A. Risk Factors – We may be unable to meet our drilling obligations" for a discussion of our drilling obligations relating to our Piceance basin properties. In 2010, we plan to run a one rig program.

Reserves

The following table shows our total estimated net proved reserves at December 31, 2009:

Net proved reserves:	2009
Proved Developed:	
Oil (MBbl)(1)	82,870
Natural Gas (Mmcf)(2)	255,520
Total (MBOE)(3)	125,456
Proved Undeveloped	
Oil (MBbl)	47,070
Natural Gas (Mmcf)	376,658
Total (MBOE)	109,847
Total Proved:	
Oil (MBbl)	129,940
Natural Gas (Mmcf)	632,178
Total (MBOE)	235,303

(1) MBbl – Thousand barrels
(2) Mmcf – Thousand Mcfs
(3) MBOE – Thousand BOEs (6 Mmcf : 1 MBOE)

During 2009, we invested approximately $93 million in the conversion of proved undeveloped reserves to proved developed reserves. We converted approximately 7 MMBOE of proved undeveloped reserves to proved developed reserves during 2009. At December 31, 2009, less than 1% of our proved undeveloped reserves in individual fields remained undeveloped for five years or more. We estimate these reserves will be developed over the next three years.

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 product 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. for the years ended December 31, 2009, 2008 and 2007. We engaged DeGolyer and McNaughton (D&M) to prepare 100% our proved oil and gas reserve estimates and the 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 accepted 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 natural gas and oil calculated as the un-weighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period 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 DeGoyler and MacNaughton dated February 19, 2010.

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 internal 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 that we operate and has supervised operations in a majority of them. The ending reserves are also subject to multiple levels of management review.

Sensitivity of Reserves to Prices.

A significant portion of our operating costs in California are based on the price of natural gas. The requirement to use year-end costs may impact the present value of estimated future cash flows before income taxes discounted at 10% (PV10), if the un-weighted average first-day-of-the-month natural gas price is higher or lower than the year-end price of natural gas. We believe it would be meaningful to consider price sensitivities to the proved reserve calculation as follows:

	Oil (MBbl)	Natural Gas (Mmcf)	Total MBOE	Pre-Tax PV10 (1) ($ in millions)
SEC Proved Reserves (2)	129,940	632,178	235,303	1,849
Steam Injection Cost Alternative (3)	130,091	632,188	235,455	2,106

(1) Pre-tax PV10 may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows (SMOG), which is the most directly comparable GAAP financial measure. Pre-tax PV10 is computed on the same basis as the SMOG but without deducting future income taxes. We believe pre-tax PV10 is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10 as a basis for comparison of the relative size and value of our reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10 is not a substitute for the SMOG. Our pre-tax PV10 and the SMOG do not purport to present the fair value of our oil and natural gas reserves. The following table shows the reconciliation of SMOG to the pre-tax PV10 value.

	SEC Proved Reserves	Steam Injection Cost Alternative
SMOG	1,446	1,611
Discounted future cash flow from income taxes	403	495
Discounted future net cash flow before income taxes (PV10)	1,849	2,106

(2) SEC proved reserves have been calculated in accordance with current authoritative guidance.

(3) Steam injection cost alternative assumptions were based on using the un-weighted arithmetic average of the first-day-of-the-month price for each month during the calendar year for the basis of determining our steam injection costs, as compared to using the end of the year natural gas price to determine our steam injection costs.
The 2009 year end natural gas price used to calculate steam costs was $6.20/Mcfe compared to the 2009 un-weighted arithmetic average of the first-day-of-the-month natural gas price of $3.93/Mcfe. All other inputs and assumptions remain the same as those used in calculating the SEC proved reserves.

Operations. In California, we operate all of our principal oil and gas producing properties. The California assets consist of heavy crude oil which requires heat, supplied in the form of steam, which is 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. Field operations related to oil production include the initial recovery of the crude oil and its transport through treating facilities into storage tanks. After the treating process is completed, which includes removal of water and solids by mechanical, thermal and chemical processes, the crude oil is metered through automatic custody transfer units or gauged before sale and subsequently transferred into crude oil pipelines owned by other companies or transported via truck.

In the Rocky Mountains, crude oil produced from the Uinta properties is transported by truck. Natural gas produced from the Uinta and Piceance properties is transported to one of several main pipelines. We have firm transportation contracts on two different pipelines to provide transport for our Rocky Mountain natural gas production. In E. Texas, natural gas produced from the Darco and Oakes properties is transported intra-state on the Enbridge system to various market points. See Firm Transportation Summary on page 9.

Crude Oil and Natural Gas Marketing

Economy. Oil is a globally priced commodity and is priced according to the supply and demand of crude oil and its products. The range of NYMEX light sweet crude prices for 2009, based upon settlements, was a low of $33.98 and a high of $81.37.

	2009	2008	2007
Average NYMEX settlement price for WTI	$ 62.09	$ 99.75	$ 72.41
Average posted price for:			
Utah 40 degree API black wax (light) crude oil	49.84	84.99	59.28
California 13 degree API heavy crude oil	53.54	86.51	61.64
Average crude price differential between WTI and:			
Utah light 40 degree API black wax (light) crude oil	12.25	14.76	13.13
California 13 degree API heavy crude oil	8.55	13.24	10.77

The above posting prices and differentials do not necessarily reflect the amounts paid or received by us due to the contracts discussed below. In California the differential on December 31, 2009 was $7.96 and ranged from a low of $5.20 to a high of $14.02 per barrel during the year. In Utah the differential on December 31, 2009 was $11.00 and ranged from a low of $10.00 to a high of $16.00 per barrel during the year, based on oil postings.

Oil Contracts. We market our crude oil production to competing buyers which may be independent or major oil refiners or third party marketers.

As of December 31, 2009, we have over 90% of our California oil production under contract with major oil producers through the third quarter of 2010. The remaining oil production is under contract over a long-term period with a niche refinery in the Los Angeles basin.

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 our Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil. Gross oil production from our Uinta properties averaged approximately 2,700 Bbl/D in 2009. Please see "Item 1A. Risk Factors–We may not be able to deliver minimum crude oil volumes required by our sales contract."

Natural Gas Marketing. We market our produced natural gas from Colorado, Utah and Texas. Generally, natural gas is sold at monthly index related prices. At some locations we utilize intrastate or interstate pipeline transportation to move the gas to a more favorable market point. Certain volumes are sold at a daily spot related price. As of mid-2009, the pricing of our Rocky Mountain natural gas production is tied to the eastern markets in Lebanon or Clarington Ohio. Also beginning in early 2009, the E. Texas natural gas is generally priced off the Florida Zone 1 index. Utah gas pricing remained unchanged and is generally sold on a Questar related index price.

	2009	2008	2007
Annual average closing/index price per MMBtu for:			
NYMEX Henry Hub (HH) prompt month natural gas contract last day	$ 3.99	$ 9.03	$ 6.86
Rocky Mountain Questar first-of-month indices (Uinta sales)	3.02	6.15	3.69
Rocky Mountain CIG first-of-month indices (WY and former Piceance sales)	3.07	6.24	3.97
Mid-Continent PEPL first-of-month indices (former Piceance sales)	3.24	7.08	5.99
Eastern Market Lebanon, Ohio first-of-month indices (Aug 2009 – Dec 2009)	3.77	n/a	n/a
Texas Eastern – E. Texas first-of-month indices	3.58	8.46	n/a
Florida Zone 1 first-of-month indices (E. Texas sales)	3.87	n/a	n/a
Average natural gas price per MMBtu differential between NYMEX HH and:			
Questar	0.97	2.88	3.17
CIG	0.92	2.79	2.89
PEPL	0.75	1.95	.87
Lebanon (Aug 2009 – Dec 2009)	(0.03)	n/a	n/a
Texas Eastern – E. Texas	0.41	0.57	n/a
Florida Zone 1	0.12	n/a	n/a

Gas Basis Differential. We have contracted a total of 35,000 MMBtu/D on the Rockies Express Pipeline (REX) under two separate transactions to provide firm transport for our Piceance gas production. Upon the start-up of REX in mid-2009, the sales point for our Piceance natural gas moved from the Rockies to the Mid-Continent under REX West and finally to the eastern Ohio market with REX East. By year-end 2009, the Piceance natural gas was selling at, or above, Henry Hub. The bulk of the Uinta basin gas continues to sell on a Questar index related price. Early in 2009, Enbridge Pipeline completed its expansion to Orange County, TX. Since that time, the majority of the E. Texas natural gas has been sold with a price related to the Florida Zone 1 index.

We have physical access to interstate gas pipelines to move gas to or from market. To assure delivery of gas, we have entered into long-term gas transportation contracts as follows:

Firm Transportation Summary.

Pipeline	From	To	Quantity (Avg. MMBtu/D)	Term	December 31, 2009 demand charge per MMBtu	Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$ 0.5847	$ 8,544
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 2/2018	1.1134(1)	84,561
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	1/2008 to 1/2018	1.094(1)	32,528
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,500	9/2003 to 4/2012	0.1739	370
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,859	9/2003 to 9/2012	0.1739	499
Questar Pipeline	Brundage Canyon, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.2573	6,022
Enbridge Pipeline	Limestone and Harrison Counties, TX	Orange, TX	Up to 55,000	4/2009 to 3/2012	0.22	4,351
Total			112,359			$ 136,875

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

Steaming Operations

Cogeneration Steam Supply. As of December 31, 2009, approximately 48% of our proved reserves, or 112 million barrels, consisted of heavy crude oil produced from depths of less than 2,000 feet. 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 26 fully permitted conventional boilers. The quantity of boilers operated at any point in time is dependent on 1) the steam volume required for us to achieve our targeted production and 2) the price of natural gas compared to the realized price of crude oil sold.

Total barrels of steam per day (BSPD) capacity as of December 31, 2009 is as follows:

Steam generation capacity of conventional boilers	107,292
Steam generation capacity of cogeneration plants	42,789
Additional steam purchased under contract with a third party	2,050
Total steam capacity	152,131

The average volume of steam injected for the years ended December 31, 2009 and 2008 was 109,153 BSPD and 99,908 BSPD, respectively.

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.

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.

As of December 31, 2009, approximately 78% of the volume of natural gas purchased to generate steam and electricity is 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 22% 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 Rocky Mountain Northwest Pipeline (NWPL) index.

	2009	2008	2007
Average SoCal Border Monthly Index Price per MMBtu	$ 3.59	$ 7.92	$ 6.38
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	3.09	6.25	3.95
Average PG&E Citygate Monthly Index Price per MMBtu	4.17	8.63	6.86

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 2009 and estimated average 2010 amount of production in excess of consumption and hedged volumes (in average MMBtu/D):

	2009	Estimated 2010
Approximate natural gas volumes produced in operations	62,000	65,000
Approximate Natural gas consumed:		
Cogeneration operations	27,000	27,500
Conventional boilers (1)	24,000	34,500
Total natural gas volumes consumed in operations	51,000	62,000
Less: Our estimate of approximate natural gas volumes consumed to produce electricity (2)	(20,800)	(19,900)
Total approximate natural gas volumes consumed to produce steam	30,200	42,100
Natural gas volumes hedged	14,000	19,000
Amount of natural gas volumes produced in excess of volumes consumed to produce steam and volumes hedged	17,800	3,900

(1) In 2009, we added conventional capacity at our Poso Creek and N. Midway diatomite assets to increase our production from these fields.
(2) We estimate this volume based on the historical allocation of fuel costs to electricity.

Electricity

Generation. The total annual average electrical generation of our three cogeneration facilities is approximately 92 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 the 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 boilers. 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. Historically, we have sold electricity produced by our cogeneration facilities, each of which is a Qualifying Facility (QF) under the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA), 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; and 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 the outcome of global settlement discussions to resolve this and other QF related matters. We do not expect the prospective reduction in electricity revenue as a result of lower SRAC prices to be material to the Company.

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. Effective upon their scheduled termination, each of the three contracts was extended pursuant to the SRAC Decision, for the terms described below. Pursuant to these contracts, we are paid the purchasing utility's SRAC energy price and a capacity payment that is subject to adjustment from time to time by the CPUC, as they did in the SRAC decision. Edison and PG&E challenged, in the California Court of Appeals, the legality of the CPUC decision that ordered the utilities to enter into these five-year SO1 contracts, and similar one-year SO1 contracts that were ordered for 2004. The Court ruled that the CPUC had the right to order the utilities to execute these contracts. The Court also ruled 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 the requirements of PURPA. A CPUC proceeding to resolve this retroactive price issue is being held in abeyance pending the outcome of global settlement discussions to resolve this and other QF related matters. Our SO2 contract for the Placerita Unit 1 Facility expired on March 25, 2009. Effective upon its expiration, Berry executed an amendment with Edison to extend the non-price terms of the SO2 pursuant to the SRAC Decision until a replacement contract is approved by the CPUC and is available for execution by Berry. The payment provisions of this extension agreement reflect the payment provisions ordered in the SRAC Decision. The capacity price was reduced upon the expiration of the SO2 and the SRAC energy price was reduced effective August 1, 2009. The Company intends to enter into new SO contracts with Edison and PG&E for all three facilities as soon as the ongoing challenges are resolved and the CPUC has approved the terms of the new SO contracts.

During the California energy crisis in 2000 and 2001, we had electricity sales contracts with various utilities 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. Please 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)	16	4	6,500
S. Midway						
Cogen 18	SO1	PG&E	Dec-10 (2)	11	4	6,400
Cogen 38	SO1	PG&E	Dec-10 (2)	37	-	18,000

(1) The term of this agreement was extended until the CPUC approves a replacement contract.
(2) This agreement will terminate earlier upon CPUC approval of a replacement contract.

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 (identified on page 4).

Employees. On December 31, 2009, we had 243 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 is good.

Capital Expenditures Summary (Excluding Acquisitions).

The following is a summary of the developmental capital expenditures incurred during 2009 and 2008 and estimated capital expenditures for 2010 (in thousands):

	2010 (Estimated) (1)	2009	2008
S. Midway Asset Team			
New wells and workovers	$ 19,000	$ 18,000	$ 44,000
Facilities - oil & gas	22,000	6,000	10,000
Facilities – cogeneration	-	-	1,000
General	-	-	-
	41,000	24,000	55,000
N. Midway Asset Team			
New wells and workovers	40,000	14,000	33,000
Facilities - oil & gas	37,000	18,000	34,000
Facilities – cogeneration	3,000	-	3,000
General	1,000	-	-
	81,000	32,000	70,000
Permian Asset Team			
New wells and workovers	30,000	-	-
	30,000	-	-
Uinta Asset Team			
New wells and workovers	33,000	4,000	57,000
Facilities	2,000	1,000	2,000
General	-	1,000	-
	35,000	6,000	59,000
E. Texas Asset Team			
New wells and workovers	51,000	41,000	66,000
Facilities	-	5,000	-
General	-	1,000	-
	51,000	47,000	66,000
Piceance Asset Team			
New wells and workovers	30,000	21,000	124,000
Facilities	6,000	4,000	5,000
General	-	1,000	1,000
	36,000	26,000	130,000
DJ Asset Team	-	-	17,000
Other Fixed Assets	1,000	-	1,000
TOTAL	$ 275,000	$ 135,000	$ 398,000

(1) Estimated capital expenditures may be adjusted for numerous reasons including, but not limited to, oil and natural gas price levels and equipment availability, working capital needs, permit and regulatory issues.

Production, Average Sales Prices, and Production Costs. The following table reflects production, average sales price, and production cost information for the years ended December 31, 2009, 2008 and 2007:

	2009	2008	2007
Net annual production: (1)			
Oil (Mbbl)	7,186	7,441	7,210
Gas (MMcf)	22,657	25,559	15,657
Total equivalent barrels (MBOE) (2)	10,962	11,700	9,819
Less DJ Production (MBOE) (2)	279	1,206	1,140
Production – Continuing operations (MBOE) (2)	10,683	10,494	8,679
Average sales price for continuing operations:			
Oil (per Bbl) before hedging	$ 50.73	$ 86.90	$ 57.85
Oil (per Bbl) after hedging	57.28	70.01	53.24
Gas (per Mcf) before hedging	3.61	6.91	4.17
Gas (per Mcf) after hedging	4.09	7.11	5.48
Per BOE before hedging	41.23	73.64	52.30
Per BOE after hedging	46.59	62.03	49.80
Oil and gas production (per BOE) costs for continuing operations	14.66	17.99	15.09

Mbbl - Thousands of barrels
Mcf - Thousand cubic feet
MMcf - Million cubic feet
BOE - Barrels of oil equivalent
MBOE - Thousand barrels of oil equivalent
(1)Net production represents that owned by us and produced to our interests.
(2)Equivalent oil and gas information is at a ratio of 6 thousand cubic feet (Mcf) of natural gas to 1 barrel (Bbl) of oil. A barrel of oil is equivalent to 42 U.S. gallons

Acreage and Wells. As of December 31, 2009, our properties accounted for the following developed and undeveloped acres:

	Developed Acres		Undeveloped Acres (1)		Total	
	Gross (2)	Net (2)	Gross	Net	Gross	Net
California	5,317	5,292	1,240	1,240	6,557	6,532
Colorado	6,314	3,157	11,691	8,714	18,005	11,871
Kansas	-	-	62,810	61,856	62,810	61,856
Texas	4,794	4,523	-	-	4,794	4,523
Utah	39,280	36,635	220,905	101,878	260,185	138,513
Wyoming	3,520	539	1,746	276	5,266	815
Other	40	3	-	-	40	3
	59,265	50,149	298,392	173,964	357,657	224,113

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

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

The following table summarizes gross and net productive oil and natural gas wells at December 31, 2009. Gross wells represent the total number of wells in which we have a working interest. Net wells represent the number of gross wells multiplied by the percentages of the working interests owned by us. One or more completions in the same bore hole are counted as one well.

	Productive Wells	
	Gross	Net
Oil	2,385	2,348
Natural Gas	524	350
Total	2,909	2,698

<u>Drilling Activity.</u> The following table sets forth certain information regarding our drilling activities for the periods indicated:

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development wells drilled:						
Productive	132	132	443	374	411	314
Dry (1)	2	2	6	5	7	5
Exploratory wells drilled:						
Productive	-	-	3	2	5	3
Dry (1)	-	-	-	-	-	-
Total wells drilled:						
Productive	132	132	446	376	416	317
Dry (1)	2	2	6	5	7	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.

	2009	
	Gross	Net
Total productive wells drilled:		
Oil	121	121
Gas	11	11

We drilled 134 gross (134 net) wells during 2009, realizing a gross success rate of 99 percent. As of December 31, 2009, we have 2 rigs drilling on our properties under long-term contracts. As of December 31, 2009, we had 3 gross (3 net) wells in progress.

The following table sets forth certain information regarding drilling activities by area for the year ended December 31, 2009:

	Gross Wells	Net Wells
S. Midway	57	57
N. Midway	64	64
Uinta	2	2
Texas	11	11
Totals *(1)*	134	134

(1)Includes 2 wells that were dry holes in 2009.

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 Piceance. Two of these rigs are not currently drilling and one rig is drilling in the Uinta basin. As the rig market and our rig requirements change, we continue to evaluate the ownership of these rigs. We recorded impairment charges of $4.2 million in both 2009 and 2008 related to the disposal and impairment of our drilling rigs and related equipment. See Note 6 to the financial statements.

<u>Environmental and Other Regulations.</u> 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 drilling 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 PURPA, as amended, and the adoption of regulations thereunder 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 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 amends 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. Such a determination has not been made for our service areas in California. 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.

Item 1A. Risk Factors

Other Factors Affecting the Company's Business and Financial Results

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, results of operations and financial condition. Our revenues, profitability and future growth and reserve calculations depend substantially on the price received for our oil and gas production. These prices also affect the amount of our cash flow available for capital expenditures, working capital and payments on our debt, 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 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.

We have a substantial amount of debt and the cost of servicing that debt could limit our financial flexibility and adversely affect our business. We have a substantial amount of indebtedness. At December 31, 2009, we had total long-term outstanding debt of approximately $1.02 billion and no short-term debt. Our borrowing base under our senior secured revolving credit facility is currently approximately $938 million and, as of December 31, 2009, we had approximately $372 million (excluding $4 million of outstanding letters of credit) outstanding under our senior secured revolving credit facility, with additional borrowing availability of approximately $562 million.

We have demands on our cash resources, including, among others, operating expenses and interest and principal payments under our senior secured revolving credit facility, our senior secured money market line of credit, our 10.25¼% senior notes and our 8.25% senior subordinated notes. Our level of indebtedness relative to our proved reserves and these significant demands on our cash resources could have adverse effects on our business. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to our debt;

- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;

- require us to make principal payments under our senior secured revolving credit facility if the quantities of proved reserves attributable to our crude oil and natural gas properties are insufficient to support our level of borrowings under that credit facility;

- limit our flexibility in planning for, or reacting to, changes in the oil and gas industry;

- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;

- limit our financial flexibility, including our ability to borrow additional funds, pay dividends, make certain investments and issue equity on favorable terms or at all;

- increase our interest expense if interest rates increase, because borrowings under our senior secured revolving credit facility are at a variable rate of interest, and borrowings under our senior secured money market line of credit are generally at a variable rate of interest;

- increase our vulnerability to general adverse economic and industry conditions; and

- result in an event of default upon a failure to comply with financial covenants contained in our senior secured revolving credit facility, senior secured money market line of credit, senior subordinated notes or senior notes which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

A higher level of indebtedness increases the risk that we may default on our obligations. Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon our future performance and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital markets conditions, oil and natural gas prices, our financial condition, results of operations and prospects and other factors, many of which are beyond our control.

The borrowing base under our credit facility may be reduced below the amount of our outstanding borrowings under that facility. The amount we are able to borrow under our senior secured revolving credit facility is determined based on the value of our proved oil and natural gas reserves and is based on oil and natural gas price assumptions which vary by individual lender. Our borrowing base is subject to redetermination twice each year in April and October with the option for one additional redetermination each year and additional redeterminations contemporaneously with any issuance of permitted second lien debt and after any issuance of permitted unsecured debt. Each dollar of permitted senior unsecured debt automatically reduces the borrowing base under our senior secured revolving credit facility by 25 cents. Should there be a deficiency in the amount of our borrowing base in comparison to our outstanding debt under the senior secured revolving credit facility, we would be required to repay any such deficiency in two equal installments, 90 and 180 days after the redetermination. If we were unable to make those repayments, we would be in default under our senior secured revolving credit facility, which could have a material adverse effect on our business and financial condition.

Our heavy crude oil in California may be less economic than lighter crude oil and natural gas. As of December 31, 2009, approximately 48% of our proved reserves, or 112 million barrels, consisted of heavy oil. Light crude oil represented 8% and natural gas represented 44% of our oil and natural gas reserves. Heavy crude oil 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 the EOR process of 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. We had a long-term contract to sell all of our heavy crude oil in California for approximately $8.10 below WTI with Big West of California (BWOC). On December 22, 2008, Flying J, Inc. and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC each filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed us that it was unable to receive our production. On March 17, 2009, we entered into a stipulation with BWOC, terminating the contract effective as of March 16, 2009. We recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of that $38.5 million due from BWOC, $11.8 million represents 20 days of our December 2008 crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November 2008 and the balance of December 2008 crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract. While we also have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, the information received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected.

Additionally, 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.

We may be unable to meet our drilling obligations. We have contractual obligations on our Piceance assets in Colorado. We must spud 120 wells by February 2011 to avoid penalties of $0.2 million per well. Our ability to meet this commitment depends on the capital resources available to us to fund our activities to develop these assets on the schedule required to avoid penalties or loss of related leases. There is no assurance that our operating cash flow or alternative sources of capital investment from partnerships, joint ventures or other investment opportunities with third parties will be available to us in sufficient amount to develop these assets on the schedule required to avoid penalties.

Our financial counterparties may be unable to satisfy their obligations. We rely on financial institutions to fund their obligations under our senior secured credit facility 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 two 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.

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, 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 natural gas and crude oil differentials.

Price differentials may widen in the future. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, 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 based on 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, insufficient pipeline 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 the benchmark price for oil and natural gas and the wellhead price we receive could adversely affect our financial condition.

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 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 five 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 Bbl/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 2,700 Bbl/D in 2009.

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 28% of our steam capacity as of December 31, 2009. These facilities are dependent on reasonable power 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 power 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. Our power contracts have been extended until December 31, 2010, but are subject to earlier termination by the utility counterparty in certain 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. All of our power contracts in place with the utilities are expected to terminate in 2010, and while we intend to enter into future contracts with the utilities, all of the terms of such contracts are currently the subject of contested proceedings before the California Public Utilities Commission (CPUC). 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 new SRAC pricing formula retroactively, if applied so as to require payment on a one-time basis, could have a material adverse effect on our financial condition and results of operations. During the California energy crisis in 2000 and 2001, we had electricity sales contracts with various utilities 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. See “Item 1. Business - Electricity” for more information about our electricity contracts.

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 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 gas price and interest rate hedging 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 hedging transactions with respect to a portion of our oil and 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. We also utilize interest rate hedges 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 hedging transactions 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. Hedging 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 gas reserves. To maintain production levels, we must locate and develop or acquire new oil and 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 to acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and 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 gas reserves.

Actual quantities of recoverable oil and gas reserves and future cash flows from those reserves, future production, oil and 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 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 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 and exploration and prevailing oil and 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 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. Declines in oil and natural gas prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, 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 gas properties under the successful efforts accounting method. If net capitalized costs of our oil and 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 gas properties is computed on a field-by-field basis. Once incurred, a write-down of oil and gas properties is not reversible at a later date even if oil or gas prices increase. It is possible that declining 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 facility.

Approximately 47% of our total estimated proved reserves at December 31, 2009 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 and results of operations. 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 gas companies actively bid for desirable oil and 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 gas industry. 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 and results of operations.

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 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;
- 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. For example, although we expect that our diatomite production will average approximately 5,000 BOE/D by the end of 2010, actual production from these assets could be significantly lower.

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

- fires;
- explosions;
- blow-outs;
- uncontrollable flows of oil, 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;
- 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 and results of operations. 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 complex 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. All facets of our operations are regulated extensively at the federal, state, regional and local levels. Environmental laws and regulations impose limitations on our discharge of pollutants into the environment, establish standards for our management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose on us obligations to investigate and remediate contamination in certain circumstances. We also must satisfy, in some cases, federal and state requirements for providing environmental assessments, environmental impact studies and/or plans of development before we commence exploration and production activities. Environmental and other requirements applicable to our operations generally have become more stringent in recent years, and compliance with those requirements more expensive. Frequently changing environmental and other governmental 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 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 penalties.

From time to time we have experienced accidental spills, leaks and other discharges of contaminants at some of our properties. We could be liable for the investigation or remediation of such contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage. We have incurred expenses and penalties in connection with remediation of contamination 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 even where the contamination does not result from 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 to attempt to stop such projects, including decisions by the 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 oil and natural gas. There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of greenhouse gasses (GHG). Moreover, in 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for GHGs, became binding on all those countries that had ratified it. International discussions are currently underway to develop a treaty to replace the Kyoto Protocol after its expiration in 2012. While it is not possible at this time to predict how regulation that may be enacted to address GHG emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, and the proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process. The adoption of any future federal or state laws or implementing regulation imposing reporting obligation 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 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 and results of operations.

The adoption of derivative legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business. Congress is currently considering legislation to impose restrictions on certain derivatives, including in some cases energy derivatives, which could affect the use of derivatives in hedging transactions. For example, the "cap and trade" legislation contains provisions that, until other derivative regulation is enacted, would subject almost all energy commodity derivative transactions, including hedging, to the authority of the Commodity Futures Trading Commission, which can impose capital, margin and position limits on traders and require on-exchange trading and other forms of regulation. Separately, the House of Representatives adopted financial regulatory reform legislation on December 11, 2009, that, among other things, would impose comprehensive regulation on the over-the-counter derivatives marketplace. Although it is not possible at this time to predict whether or when Congress may act on derivatives regulation legislation, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge certain risks associated with our business or on the cost of our hedging activity.

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 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 and environmental problems that may exist or arise. Our review prior to signing a definitive purchase agreement may be even more limited.

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 acquiring producing properties, 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 results of operations and financial condition 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 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.

In 2008, we executed two transportation precedent agreements with Ruby Pipeline LLC (Ruby), which was proposing to construct a pipeline with a capacity of 1,500,000 decatherms per day from the Opal Hub in southwest Wyoming to the Malin Hub at the California-Oregon border. One of the precedent agreements is for 25,000 decatherms per day commencing upon operation of the pipeline and the other is for 12,857 decatherms commencing two years after the commencement of operation of the pipeline for an average of 35,000 decatherms per day over the 10 year term. One of the conditions, among many, under these agreements, is that we will maintain evidence of satisfaction of creditworthiness. Under the agreements, we as the shipper have the option to choose among a variety of creditworthiness supports, one of which is that the two parties have to reach a mutually agreeable creditworthiness support. Ruby’s initial proposal is not acceptable to us and on January 29, 2010, we proposed an alternative credit arrangement that would be satisfactory to us and would be consistent with that offered by Ruby to other shippers who we believe are less creditworthy than us. On February 9, 2010, Ruby responded by rejecting Berry’s proposal and filing a lawsuit against us. This dispute may result in a termination of our contracts for capacity on this pipeline in which case we will make alternative arrangements for the transportation and marketing of our production. Additionally, the termination of these contracts may also result in monetary damages.

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 Federal Energy Regulatory Commission (FERC) as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional 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, that 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.

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 the results of our operations and financial condition. 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 title problems, the amount paid for affected oil and natural gas leases or estates can be generally lost, and a prospect can become undrillable.

We have received a notice of proposed civil penalty of $69.6 million from the Bureau of Land Management that may result in our payment of a significant penalty. In July 2009, we received a notice of proposed civil penalty from the Bureau of Land Management (the BLM) related to our alleged non-compliance during 2007 with regulations relating to the operation and position of certain valves in our Uinta basin operations. The regulations are intended to address production security on Federal and tribal lands managed by the BLM. The proposed civil penalty is $69.6 million and reflects the theoretical maximum penalty amount under applicable regulations, absent mitigating factors. We immediately remediated the instances of non-compliance in 2007, cooperated fully with the BLM's investigation and we believe no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, we believe this matter will be resolved by the payment of a penalty that will not exceed $2.1 million and have accrued such amount in the second quarter of 2009. However, there can be no assurance that any penalty would not be in excess of $2.1 million or have a material adverse affect on us.

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 liquidity.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the most recently ended fiscal quarter.

Executive Officers. Listed below are the names, ages (as of December 31, 2009) and positions of our executive officers and their business experience during at least the past five years. All our officers are reappointed in May of each year at an organizational meeting of the Board of Directors. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 56, 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 2003. 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, 39, 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 participated in numerous equity, debt and M&A transactions in the energy industry.

MICHAEL DUGINSKI, 43, 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 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, 49, 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, 47, 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, 66, 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 us. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

SHAWN M. CANADAY, 34, has held the position of Vice President of Finance and Treasurer since August 2009 and 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, 46, has held the position of Vice President, Corporate Development since January 2010, 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.

KENNETH A. OLSON, 54, has been Corporate Secretary since December 1985 and was Treasurer from August 1988 until December 2004.

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, referred to collectively as the "Capital 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 Common Stock at the option of the holder.

Our Class A Common Stock is listed on the New York Stock Exchange (NYSE) under the symbol BRY. The Class B Stock is not publicly traded. The market data and dividends for 2009 and 2008 are shown below:

	2009			2008		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$ 13.10	$ 5.50	$ .075	$ 47.20	$ 33.41	$ .075
Second Quarter	22.76	10.52	.075	62.15	45.73	.075
Third Quarter	28.46	14.90	.075	61.72	30.99	.075
Fourth Quarter	31.37	24.87	.075	37.76	6.02	.075
Total Dividends Paid			$ .300			$ .300

The number of holders of record of our Class A Common Stock was 544 as of February 1, 2010. There was one Class B Shareholder of record as of February 1, 2010.

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, 2009, we have paid dividends on our Common Stock for 81 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 1) senior secured revolving credit facility to the greater of $20 million or 75% of net income, and 2) bond indentures of up to $20 million annually irrespective of our coverage ratio or net income 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	3,653,340	$ 25.36	218,635
Equity compensation plans not approved by security holders	none	none	none

Issuer Purchases of Equity Securities.

None.

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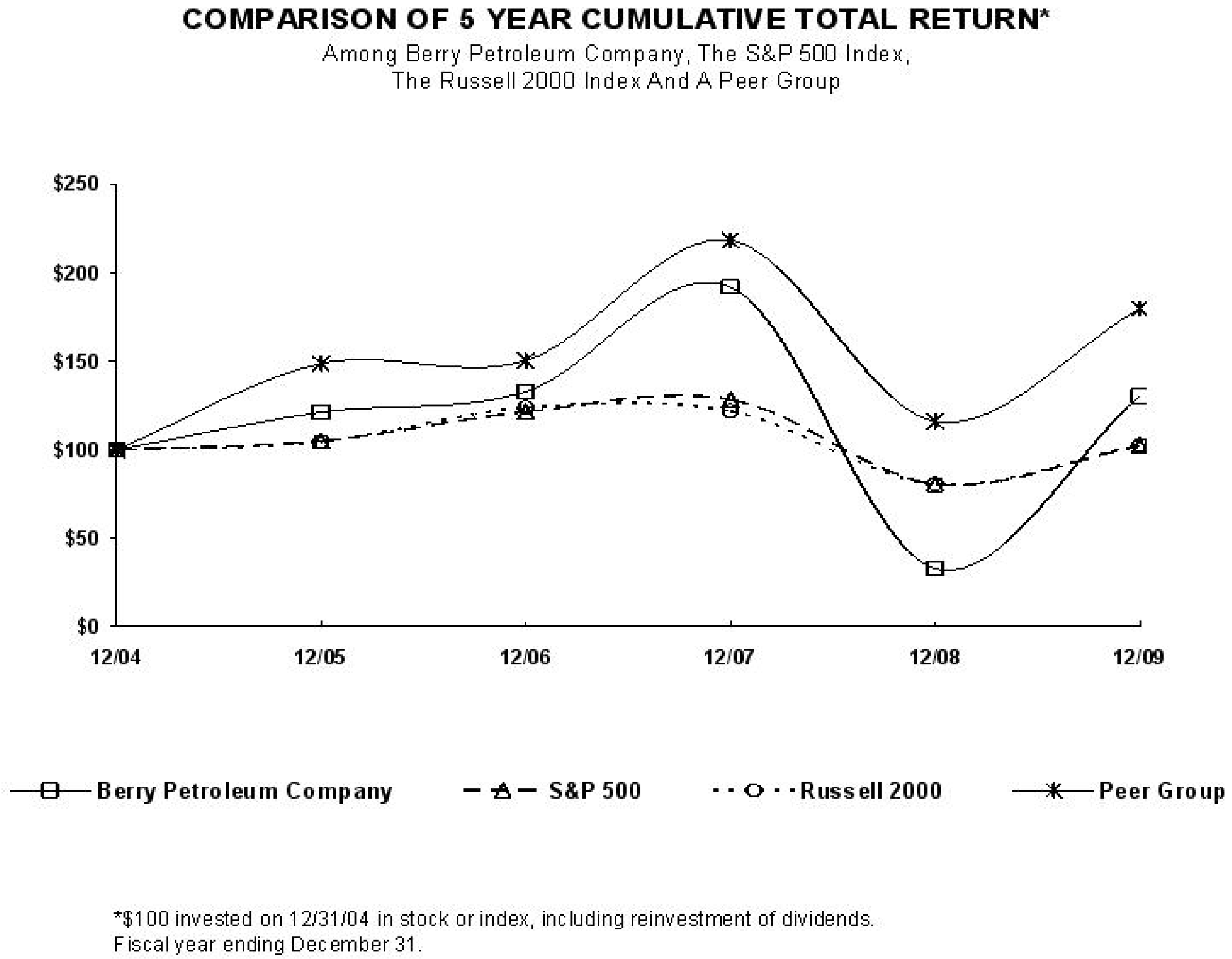
Performance Graph

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, 2004 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index (S&P 500) 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 15 companies which make up the Peer Group are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Encore Acquisition Co., Forest Oil Corp., Petrohawk Energy Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Range Resources Corp., St. Mary Land & Exploration Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp.



	12/04	12/05	12/06	12/07	12/08	12/09
Berry Petroleum Company	100.00	121.11	132.63	191.74	33.06	130.22
S&P 500	100.00	104.91	121.48	128.16	80.74	102.11
Russell 2000	100.00	104.55	123.76	121.82	80.66	102.58
Peer Group	100.00	148.61	150.33	218.15	116.04	179.66

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 and have been revised from the presentation, except for the reserve data, to reflect (1) the presentation as discontinued operations of our DJ Basin assets, which were sold on April 1, 2009 and (2) our implementation of authoritative guidance related to whether instruments granted in share based payment transactions are participating securities, which requires the revision of prior period basic and diluted earnings per share data. The statements of income data for the years ended December 31, 2009, 2008 and 2007 and balance sheet data as of December 31, 2009 and 2008 included in this table were derived from the audited financial statements and the accompanying notes to those financial statements (in thousands, except per share, per BOE and % data).

	2009	2008	2007	2006	2005
Financial Information					
Sales of oil and gas	$ 506,691	$ 649,248	$ 433,208	$ 396,497	$ 324,473
Sales of electricity	36,065	63,525	55,619	52,932	55,230
Gas marketing sales	22,806	35,750	-	-	-
Gain (loss) on sale of assets (1)	826	(1,297)	54,173	103	130
Operating costs - oil and gas production	156,612	188,758	130,940	111,490	93,423
Operating costs - electricity generation	31,400	54,891	45,980	48,281	55,086
Gas marketing expense	21,231	32,072	-	-	-
Production taxes	18,144	26,876	14,651	12,169	10,462
General and administrative expenses (G&A)	49,237	54,279	39,663	36,474	21,270
Depreciation, depletion & amortization (DD&A)					
Oil and gas production	139,919	125,595	82,861	61,419	34,320
Electricity generation	3,681	2,812	3,568	3,343	3,260
Income from continuing operations	59,968	121,776	127,284	97,857	103,684
(Loss) income from discontinued operations, net of taxes	(5,938)	11,753	2,644	10,086	8,672
Net income	54,030	133,529	129,928	107,943	112,356
Basic net income from continuing operations per share	1.31	2.70	2.85	2.21	2.34
Basic net (loss) income from discontinued operations per share	(0.13)	0.26	0.06	0.23	0.20
Basic net income per share	1.18	2.96	2.91	2.44	2.54
Diluted net income from continuing operations per share	1.30	2.66	2.81	2.18	2.31
Diluted net (loss) income from discontinued operations per share	(0.13)	0.26	0.06	0.22	0.19
Diluted net income per share	1.17	2.92	2.87	2.40	2.50
Working deficit	(48,661)	(71,545)	(110,350)	(116,594)	(54,757)
Total assets	2,240,135	2,542,383	1,452,106	1,198,997	635,051
Long-term debt	1,008,544	1,131,800	445,000	390,000	75,000
Shareholders' equity	703,259	827,544	459,974	427,700	334,210
Cash dividends per share	0.30	0.30	0.30	0.30	0.30
Cash flow from operations	212,576	409,569	238,879	258,475	187,780
Exploration and development of oil and gas properties	134,946	397,601	285,267	286,416	130,480
Property/facility acquisitions (1)	13,497	667,996	56,247	257,840	112,249
Unaudited Operating Data					
Oil and gas producing continuing operations (per BOE (2)):					
Average sales price before hedging	$ 41.23	$ 73.64	$ 52.30	$ 50.01	$ 46.11
Average sales price after hedging	46.59	62.03	49.80	48.09	40.60
Average operating costs - oil and gas production	14.66	17.99	15.09	13.45	12.06
Production taxes	1.70	2.56	1.69	1.47	1.35
G&A	4.61	5.17	4.57	4.40	2.75
DD&A - oil and gas production	$ 13.10	$ 11.97	$ 9.55	$ 7.41	$ 4.43
Total Production (MBOE)	10,962	11,700	9,819	9,270	8,401
Less DJ Basin Production (MBOE)	279	1,206	1,140	978	656
Production – Continuing operations (MBOE)(2)	10,683	10,494	8,679	8,292	7,745
Production (MMWh)	766	755	779	757	741
Total proved reserves (BOE) (3) (5)	235,303	245,940	169,179	150,262	126,285
Standardized measure (3) (4) (5)	$ 1,445,747	$ 1,135,581	$ 2,419,506	$ 1,182,268	$ 1,251,380
Year end average BOE price for PV10 purposes (3) (5)	$ 38.37	$ 30.03	$ 66.27	$ 41.23	$ 48.21

(1) See Note 6 to the financial statements
(2) Gives effect to the DJ basin asset sale and represents continuing operations only
(3) Does not give effect to the DJ basin asset sale
(4) See Supplemental Information About Oil & Gas Producing Activities (unaudited)
(5) The new SEC and FASB reserves reporting rules require the use of 12-month average commodity prices effective for 2009, instead of year-end commodity prices used in 2008 and 2007.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

The following discussion and analysis should be read in conjunction with the “Selected Financial Data” and the accompanying financial statements and related notes included elsewhere in this Annual Report on Form 10-K. The following discussion contains forward looking statements that reflect our future plans, estimates, beliefs and expected performance. Our actual results may differ materially because of a number of risks and uncertainties. Some of these risks and uncertainties are detailed in Part I, Item 1A – “Risk Factors,” and elsewhere in this Form 10-K.

Overview. We seek to increase shareholder value through consistent growth in our production and reserves, both through the drill bit and 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
- Grow oil production from our inventory of organic development projects
- Increase natural gas production that will meet the growing demand for steam generation
- Invest our capital in a disciplined manner and maintain a strong financial position
- Acquire additional resources with an emphasis on crude oil

Notable Items in 2009.

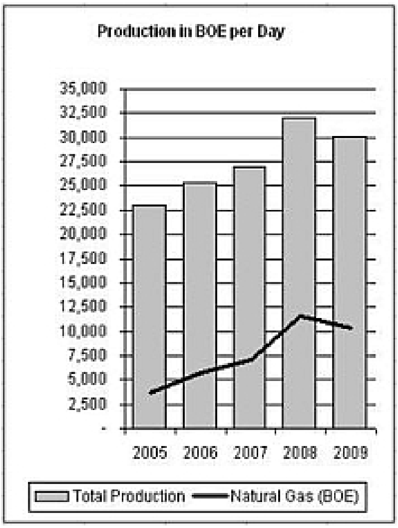
- Achieved total production averaging 30,034 BOE/D, of which 66% is crude oil production, with $135 million of capital investment
- Added 21.5 million BOE of proved reserves, ending 2009 at 235 million BOE
- Drilled 51 wells in the diatomite, increasing production 68% over 2008 levels to average 3,100 BOE/D in 2009
- Acquired property and initiated a steam flood pilot near McKittrick, California with development potential similar to our Poso Creek asset
- Acquired deep rights on our E. Texas Darco property providing an additional 13 Haynesville horizontal locations
- Implemented a new completion method in the Piceance basin, improving well results compared to our historical field average
- Issued $450 million of 10.25% senior unsecured notes due in 2014
- Closed on the sale of our DJ basin assets with proceeds of $154 million
- Completed the sale of our E. Texas midstream assets for $18 million

Notable Items and Expectations for 2010.

- Expecting 2010 capital expenditures between $250 million and $290 million to be fully funded from operating cash flow
- Anticipating average production between 32,250 and 33,000 BOE/D, a 7% to 10% increase over 2009
- Expecting diatomite production to exit 2010 at 5,000 BOE/D
- Entered into an agreement to acquire 6,900 net acres and 11 MMBOE of proved reserves, primarily in the Wolfberry trend in W. Texas for approximately $126 million
- Entered into an agreement to purchase an additional 3,200 acres and 2 MMBOE of proved reserves in the Wolfberry trend for $14 million
- Issued 8 million shares for net proceeds of $224 million to fund the Wolfberry acquisition and reduce debt
- Increased liquidity to over $650 million

Overview of the Fourth Quarter of 2009. We had net income from continuing operations of $13 million, or $0.28 per diluted share, and cash provided from operations of $64 million in the fourth quarter of 2009. Net income from continuing operations includes $3.6 million related to an unrealized gain on ineffective hedges and impairment charges of $4.2 million related to the write-down of a rig and the write-down of expired leases. Also included in the fourth quarter of 2009 are adjustments to correct the prior accounting for our royalties in the amount of $2.7 million, net of tax, which resulted in decreasing our sales of oil and gas and increasing our royalties payable. We drilled 41 gross wells, and capital expenditures, excluding property acquisitions, totaled $40 million. We achieved average production of 29,149 BOE/D in the fourth quarter of 2009, up 3% from the third quarter of 2009.

Revenue and Production.



Revenues. Approximately 88% of our revenues are generated through the sale of oil and natural gas production under either negotiated contracts or spot gas purchase contracts at market prices. Approximately 6% of our revenues are derived from electricity sales from cogeneration facilities which supply approximately 28% of our steam requirement for use in our California thermal heavy oil operations. We have invested in these facilities for the purpose of lowering our steam costs, which are significant in the production of heavy crude oil. The remaining 6% of our revenues are primarily derived from gas marketing sales which represent our excess capacity on the Rockies Express pipeline which we used to market natural gas for our working interest partners.

Sales of oil and gas decreased 22% in 2009 compared to 2008. The decrease in oil and natural gas prices resulted in a 24% decrease in sales of oil and natural gas. The decrease was offset by an increase in production volumes. Approximately 66% of our oil and gas sales volumes in 2009 were crude oil, with 56% of the crude oil being heavy oil produced in California which was sold under various contracts with prices tied to the San Joaquin posted price.

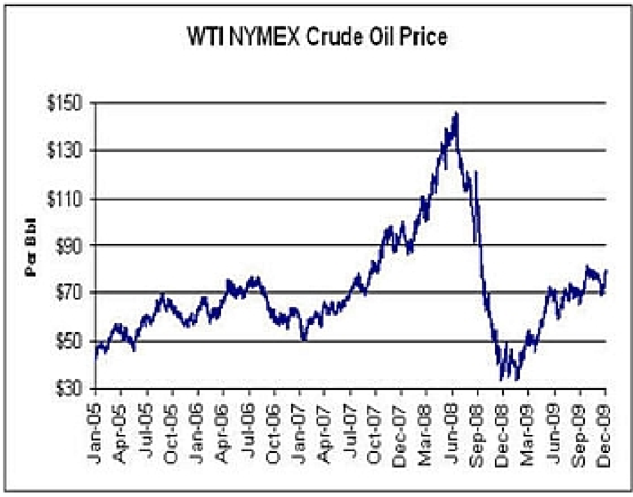
The following results are in millions (except per share data) for the years ended December 31:

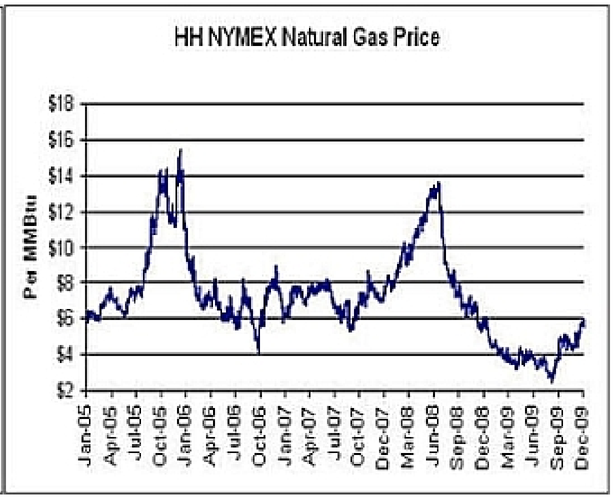
	2009	2008	2007
Sales of oil	$ 420	$ 519	$ 385
Sales of gas	87	130	48
Total sales of oil and gas	$ 507	$ 649	$ 433
Sales of electricity	36	64	56
Gas marketing	23	36	-
Gain on derivatives	6	-	-
Gain (loss) on sale of assets (1)	1	(1)	54
Interest and other income, net	2	3	4
Total revenues and other income	$ 575	$ 751	$ 547
Net income from continuing operations	$ 60	$ 122	$ 127
Diluted earnings per share from continuing operations	$ 1.30	$ 2.66	$ 2.81

(1) Includes 2007 sale of Montalvo, California assets

The following results are in millions (except per share data) for the three months ended:

	December 31, 2009	December 31, 2008	September 30, 2009
Sales of oil	$ 109	$ 97	$ 109
Sales of gas	24	38	18
Total sales of oil and gas	$ 133	$ 135	$ 127
Sales of electricity	10	12	9
Gas marketing	5	8	5
Gain (loss) on sale of assets	-	(2)	1
Interest and other income, net	-	1	1
Total revenues and other income	$ 148	$ 154	$ 143
Net income (loss) from continuing operations	$ 13	$ (11)	$ 18
Diluted earnings (loss) per share from continuing operations	$ 0.28	$ (0.24)	$ 0.40





The following table is for the years ended December 31:

		2009	%		2008	%		2007	%
Oil and Gas									
Heavy Oil Production (Bbl/D)		16,842	56		16,633	52		16,170	60
Light Oil Production (Bbl/D)		2,846	10		3,697	12		3,583	13
Total Oil Production (Bbl/D)		19,688	66		20,330	64		19,753	73
Natural Gas Production (Mcf/D)		62,074	34		69,834	36		42,895	27
Total Production (BOE/D)		30,034	100		31,968	100		26,902	100
Less DJ basin production		765			3,295			3,123	
Production – Continuing operations (BOE/D)		29,269			28,673			23,779	
Oil and gas, per BOE, for continuing operations:									
Average sales price before hedging	$	41.23		$	73.64		$	52.30	
Average sales price after hedging		46.59			62.03			49.80	
Oil, per Bbl for continuing operations:									
Average WTI price	$	62.09		$	99.75		$	72.41	
Price sensitive royalties		(2.04)			(2.95)			(5.03)	
Gravity differential and other		(9.08)			(11.32)			(9.53)	
Crude oil hedges reported with Sales of oil and gas		7.47			(16.89)			(4.61)	
Crude oil hedges reported with Gain on derivatives (a)		(0.92)			-			-	
Correction to royalties payable (b)		(0.24)			1.42			-	
Average oil sales price after hedging	$	57.28		$	70.01		$	53.24	
Natural gas price for continuing operations:									
Average Henry Hub price per MMBtu	$	4.00		$	9.04		$	7.12	
Conversion to Mcf		0.20			0.46			.36	
Natural gas hedges reported with Sales of oil and gas		0.53			0.20			1.31	
Natural gas hedges reported with Gain on derivatives (a)		(0.04)			-			-	
Location, quality differentials and other		(0.60)			(2.59)			(3.31)	
Average gas sales price after hedging	$	4.09		$	7.11		$	5.48	

(a) *Includes cash settlements on hedges for which the Company has not elected hedge accounting that are recorded in "Gain (Loss) on hedges.*

(b) *Included in 2009 is a correction to one of our royalties in the amount of $1.9 million, which resulted in decreasing our sales of oil and gas and increasing our royalties payable.*

Production from continuing operations increased 2%, or 596 BOE/D, for the year ended December 31, 2009 compared to the year ended December 31, 2008. The increase is the result of additional development activities during the year in the diatomite and the benefit of a full year of E. Texas production in 2009. These increases were offset by decreases in the Uinta basin, the S. Midway field and the Piceance basin where there was very little capital activity during the year.

Production from continuing operations increased 21%, or 4,894 BOE/D, for the year ended December 31, 2008 when compared to the year ended December 31, 2007. Our E. Texas acquisition which closed on July 15, 2008, contributed 2,384 BOE/D on an annualized basis. Our development activities during 2008 resulted in production increases in the Piceance, Poso and diatomite of 1,796 BOE/D, 1,133 BOE/D and 851 BOE/D, respectively.

The following table is for the three months ended:

	December 31, 2009	%	December 31, 2008	%	September 30, 2009	%
Oil and Gas						
Heavy Oil Production (Bbl/D)	17,280	60	15,999	45	16,780	59
Light Oil Production (Bbl/D)	2,719	9	3,659	10	2,530	9
Total Oil Production (Bbl/D)	19,999	69	19,658	55	19,310	68
Natural Gas Production (Mcf/D)	54,899	31	95,548	45	54,637	32
Total production (BOE/D)	29,149	100	35,583	100	28,417	100
Less DJ basin production	-		3,415		-	
Production – Continuing operations (BOE/D)	29,149		32,168		28,417	
Oil and gas, per BOE, for continuing operations :						
Average sales price before hedging	$ 50.76		$ 40.61		$ 45.41	
Average sales price after hedging	47.08		45.56		46.39	
Oil, per Bbl:						
Average WTI price	$ 76.13		$ 59.08		$ 68.24	
Price sensitive royalties	(2.64)		(1.69)		(2.36)	
Gravity differential and other	(9.63)		(8.55)		(8.78)	
Crude oil hedges reported with Sales of oil and gas	(3.96)		-		2.28	
Crude oil hedges reported with Gain on derivatives (a)	(2.16)		4.69		(1.41)	
Correction to royalties payable (b)	(1.78)		-		-	
Average oil sales price after hedging	$ 55.96		$ 53.53		$ 57.97	
Natural gas price for continuing operations:						
Average Henry Hub price per MMBtu	$ 4.17		$ 6.95		$ 3.39	
Conversion to Mcf	0.21		.35		0.17	
Natural gas hedges reported with Sales of oil and gas	0.40		-		0.27	
Natural gas hedges reported with Gain on derivatives (a)	(0.11)		.89		(0.07)	
Location, quality differentials and other	(0.12)		(2.67)		(0.28)	
Average gas sales price after hedging	$ 4.55		$ 5.52		$ 3.48	

(a) Includes cash settlements on hedges for which the Company has not elected hedge accounting that are recorded in "Gain (Loss) on hedges."

(b) Included in the fourth quarter of 2009 is a correction to one of our royalties in the amount of $3.3 million, which resulted in decreasing our sales of oil and gas and increasing our royalties payable.

Production from continuing operations decreased 9%, or 3,019 BOE/D, for the fourth quarter of 2009 compared to the fourth quarter of 2008, primarily due to production decreases in the Uinta basin and the Piceance basin where there was very little capital activity during 2009.

Production from continuing operations increased 3%, or 732 BOE/D, for the fourth quarter of 2009 compared to the third quarter of 2009 primarily due to development activities during the fourth quarter of 2009 that resulted in an increase in the diatomite.

Electricity. Electricity revenues and operating costs decreased in the year ended 2009 compared to the year ended 2008 as a result of 34% lower electricity prices and 56% lower natural gas prices. Electricity revenues and operating costs increased in the year ended 2008 compared to the year ended 2007 due to 18% higher electricity prices and 27% higher natural gas prices. We purchased approximately 27 MMBtu/D as fuel for use in our cogeneration facilities for the year ended December 31, 2009 and the year ended December 31, 2008. In 2009 and 2008, our electricity operations improved partially from the lower cost of the firm transportation natural gas we purchased. We purchase and transport 12,000 average MMBtu/D on the Kern River Pipeline under our firm transportation contract and use this gas to produce conventional and cogeneration steam in the Midway-Sunset field. The differential between Rocky Mountain gas prices and Southern California Border prices decreased during 2009 compared to 2008 and in 2008 compared to 2007.

The following table is for the years ended December 31:

	2009	2008	2007
Electricity			
Revenues (in millions)	$ 36.1	$ 63.5	$ 55.6
Operating costs (in millions)	$ 31.4	$ 54.9	$ 46.0
Decrease to total oil and gas operating expenses per barrel	$ 0.43	$ 0.74	$ 0.98
Electric power produced - MWh/D	2,098	2,063	2,133
Electric power sold - MWh/D	1,907	1,873	1,932
Average sales price/MWh (no hedging was in place)	$ 60.99	$ 92.98	$ 78.62
Fuel gas cost/MMBtu (including transportation)	$ 3.75	$ 7.95	$ 6.08

Royalties. A price-sensitive royalty burdens certain of our S. Midway properties which produced approximately 2,100 BOE/D in 2009. This royalty was 75% of the amount of the heavy oil posted price above a base price which was $16.43 in 2009. This royalty rate was reduced to 53% effective January 1, 2008 as long as we maintain a minimum steam injection level. We met the steam injection level in 2009 and expect to meet the requirement going forward. This base price escalates at 2% annually, thus the threshold price is $16.76 per barrel in 2010. Liabilities payable for these royalties were $15 million, $22 million and $36 million in the years ended December 31, 2009, 2008 and 2007, respectively.

Included in the fourth quarter of 2009 are adjustments to correct the prior accounting for our royalties in the amount of $3.3 million, which resulted in decreasing our sales of oil and gas and increasing our royalties payable. Management concluded the impact was immaterial to the current and prior periods.

In the first quarter of 2008, we determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. We concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, the error was corrected during the first quarter of 2008, with the effect of increasing our sales of oil and gas by $10.5 million and reducing our royalties payable.

Oil and Gas Operating and Other Expenses.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008:

The following table presents information about our continuing operating expenses for each of the years ended December 31:

	Amount per BOE			Amount (in thousands)		
	2009	2008	Change	2009	2008	Change
Operating costs - oil and gas production	$ 14.66	$ 17.99	(19) %	$ 156,612	$ 188,758	(17) %
Production taxes	1.70	2.56	(34) %	18,144	26,876	(32) %
DD&A - oil and gas production	13.10	11.97	9 %	139,919	125,595	11 %
G&A	4.61	5.17	(11) %	49,237	54,279	(9) %
Interest expense	4.67	2.28	105 %	49,923	23,942	109 %
Total	$ 38.74	$ 39.97	(3) %	$ 413,835	$ 419,450	(1) %

· **Operating costs:** Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. The following table presents steam information:

	2009	2008	Change
Average volume of steam injected (Bbl/D)	109,153	99,908	9%
Fuel gas cost/MMBtu (including transportation)	3.75	7.95	(53)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	30,462	26,826	14%

Operating costs decreased $32.1 million, or 17%, for the year ended December 31, 2009 compared to the year ended December 31, 2008. The decrease is primarily the result of a 53% decrease in fuel gas cost which is directly correlated to a decrease in natural gas prices.

· **Production taxes:** Production taxes have decreased over the last year as the value of our oil and natural gas has decreased. Severance taxes in Utah, Colorado and Texas are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. We expect production taxes to track oil and natural gas prices generally.

- **Depreciation, depletion and amortization:** DD&A increased per BOE in 2009 by 9% from 2008 due to an increase in the contribution of our development properties with higher drilling and leasehold acquisition costs and the integration of our E. Texas assets which have higher finding and development costs than our legacy assets.

- **General and administrative:** Approximately 65% of our G&A is related to compensation. The primary reason for the decrease in G&A during 2009 was a 20% decrease in employee headcount primarily associated with the sale of our DJ assets, offset by a liability of $2.1 million that was established during the second quarter of 2009 for a regulatory compliance matter. In 2008 we moved our corporate headquarters from Bakersfield, California to Denver, Colorado and approximately $1.7 million was related to relocation of our employees and related expenses. Also included in G&A in 2008 was $2.3 million in rig termination penalties that we incurred during the fourth quarter of 2008 and $0.6 million for costs we incurred to evaluate the formation of a master limited partnership.

- **Interest expense:** Our total outstanding borrowings were approximately $1.0 billion at December 31, 2009 compared to $1.2 billion at December 31, 2008. The increase in interest expense between periods is due to the amortization of additional debt issuance costs and amortization of the net discount, which were incurred in June 2009 and August 2009 in connection with the issuance of our 10.25% senior notes due in 2014 as well as a higher interest rate on the 10.25% senior notes issued compared to the interest rate on the credit facility.

- **Debt extinguishment costs:** During the years ended December 31, 2009 and 2008, we recorded debt extinguishment costs of $10.8 million and $0, respectively. These costs related to credit facility borrowing base changes, issuance of senior unsecured notes, and pay off of our second lien term loan.

- **Dry hole, abandonment, impairment and exploration:** In 2009 we had dry hole, abandonment and impairment charges of $5.2 million primarily due to a $4.2 million impairment charge related to the write-down of a rig to its fair market value (see Note 2 Fair Value Measurement). We incurred exploration costs in 2009 of $0.2 million compared to $0.6 million in 2008. These costs consist primarily of geological and geophysical costs.

- In 2008 we had dry hole, abandonment, impairment and exploration charges of $10.5 million consisting primarily of $7.3 million for technical difficulties that were encountered on five wells in Piceance before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. Due to the release of our rigs we performed an impairment test which resulted in $2.4 million of impairment costs resulting from the impairment of one rig. We incurred exploration costs of $0.6 million in both 2008 and 2007. These costs consist primarily of geological and geophysical costs.

- **Bad debt expense.** We recorded $0 and $38.7 million of bad debt expense for the years ended December 31, 2009 and 2008, respectively. The $38.7 million recorded in bad debt expense for the year ended December 31, 2008 was related to the bankruptcy of BWOC.

Income Tax Expense. The effective tax rate for the year ended December 31, 2009 and 2008 was 32% and 36% , respectively. The change in the effective tax rate between periods is due to reduced state rates and the reduction in our liability related to uncertain tax positions. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences. See Note 8 to the financial statements.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007:

The following table presents information about our operating expenses for each of the years ended December 31:

	Amount per BOE			Amount (in thousands)		
	2008	2007	Change	2008	2007	Change
Operating costs - oil and gas production	$ 17.99	$ 15.09	19%	$ 188,758	$ 130,940	44%
Production taxes	2.56	1.69	51%	26,876	14,651	83%
DD&A - oil and gas production	11.97	9.55	25%	125,595	82,861	52%
G&A	5.17	4.57	13%	54,279	39,663	37%
Interest expense	2.28	1.74	31%	23,942	15,069	59%
Total	$ 39.97	$ 32.64	22%	$ 419,450	$ 283,184	48%

Our total operating costs, production taxes, G&A and interest expenses for 2008, stated on a unit-of-production basis, increased 22% over 2007. The changes were primarily related to the following items:

- **Operating costs:** Our operating costs increased primarily due to higher contract services and labor costs, higher compression, gathering, and dehydration costs and higher steam costs resulting from higher volumes of injected steam. Of the $58 million increase in operating expense compared to 2007, approximately $31 million was due to higher steam costs and approximately $4 million was due to the addition of our E. Texas assets. On a per barrel basis, E. Texas operating costs approximate $1.00/ Mcf and reduces our overall cost per barrel. The following table presents steam information:

	2008	2007	Change
Average volume of steam injected (Bbl/D)	99,908	87,990	14%
Fuel gas cost/MMBtu (including transportation)	$ 7.95	$ 6.08	31%

- **Production taxes:** 2008 production taxes increased over 2007 as the value of our oil and natural gas increased. Severance taxes, which are prevalent in Utah and Colorado, are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves.

- **Depreciation, depletion and amortization:** DD&A increased per BOE in 2008 by 25% from 2007 due to an increase in capital spending in fields with higher drilling and leasehold acquisition costs.

- **General and administrative:** In 2008, approximately 65% of our G&A was related to compensation. The primary reason for the increase in G&A during 2008 was a 15% increase in employee headcount associated with our E. Texas acquisition and the development of our assets. In 2008 we moved our corporate headquarters from Bakersfield, California to Denver, Colorado and approximately $1.7 million was incurred during the fourth quarter of 2008. $0.6 million for costs we incurred to evaluate the formation of a master limited partnership.

- **Interest expense:** Our outstanding borrowings, including our senior unsecured money market line of credit and senior subordinated notes, were $1.16 billion at December 31, 2008 compared to $459 million at December 31, 2007. Average borrowings in 2008 increased primarily due to our E. Texas acquisition. For the year ended December 31, 2008, $23 million of interest cost was capitalized.

- **Dry hole, abandonment, impairment and exploration:** In 2008 we had dry hole, abandonment and impairment charges of $10.5 million. We recorded $7.3 million for technical difficulties that were encountered on five wells in Piceance before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. We incurred exploration costs of $0.6 million in 2008 compared to $0.6 million in 2007 . These costs consist primarily of geological and geophysical costs. Due to the release of our rigs we performed an impairment test which resulted in $2.4 million of impairment costs resulting from the impairment of one rig. Additionally, we performed an impairment test of our oil and gas assets at December 31, 2008 and determined that no impairment was necessary.

  In 2007 we had dry hole, abandonment, impairment and exploration charges of $8.4 million consisting primarily of a $3.3 million impairment of our Coyote Flats prospect to reflect its fair value in conjunction with the preparation of our year end reserve estimates, a $2.9 million write down of our Bakken properties sold in September 2007, and other dry hole charges of $2.2 million.

- **Bad debt expense.** In December 2008, Flying J, Inc. and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Of the $38.7 million recorded in bad debt expense for the year ended December 31, 2008, $38.5 million relates to the allowance for bad debt taken for the bankruptcy of BWOC with the remainder due to the bankruptcy of SemCrude earlier in 2008.

Hedging. See Item 7A Quantitative and Qualitative Disclosures about Market Risk and Note 3 to the financial statements.

Estimated 2010 Oil and Gas Operating, G&A and Interest Expenses. We estimate our 2010 production volume will range between 32,250 BOE/D and 33,000 BOE/D. Based on WTI of $60.00 and NYMEX HH of $5.00 MMBtu, we expect our expenses to be within the following ranges:

	Amount per BOE		
	Anticipated range in 2010	2009	2008
Operating costs-oil and gas production (1)	$ 17.00 – 20.00	$ 14.66	$ 17.99
Production taxes (2)	1.75 – 2.25	1.70	2.56
DD&A	12.00 – 14.00	13.10	11.97
G&A	4.00 – 4.50	4.61	5.17
Interest expense	4.00 – 5.00	4.67	2.28
Total	$ 38.75 – 45.75	$ 38.74	$ 39.97

(1) We expect operating costs to increase in 2010 as compared to 2009 due to higher natural gas prices which are the primary driver of our cost to generate steam in California, offset in part by our overall cost reduction efforts.

(2) We expect production taxes will be higher on a per BOE basis as our average realized price increases due to higher commodity prices and a majority of these costs are based on a percentage of our revenue.

<u>Financial Condition, Liquidity and Capital Resources.</u>

Our exploration, development, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and our bank credit facilities as our primary sources of liquidity. We have also used the private and public markets as other sources of financing and, as market conditions have permitted, we have engaged in asset monetization transactions.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ a hedging strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flow. As of December 31, 2009 we have approximately 75% and 40% of our expected 2010 and 2011 oil production hedged in the form of swaps and collars and we have approximately 30% and 10% of our 2010 and 2011 expected natural gas production hedged in the form of swaps and collars. This level of hedging will provide a measure of certainty of the cash flow that we will receive for a portion of our production in 2010 and 2011. In the future, we may determine to increase or decrease our hedging positions. Most of our derivatives counterparties were commercial banks that are parties to our credit facilities, or their affiliates. See Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk" below for further details concerning our hedging activities.

We have a $1.5 billion senior secured revolving credit facility with a current borrowing base of $938 million and $562 million of available borrowing capacity. At December 31, 2009, we had $372 million in borrowings and $4 million in letters of credit outstanding under the credit facility. Our borrowing base is subject to semi-annual redeterminations in April and October of each year. The borrowing base is determined by the lenders (a syndicate of banks), taking into consideration the estimated value of our proved oil and gas reserves based on pricing models determined by the lenders.

In May 2009, we issued $325 million principal amount of 10.25% senior notes due 2014 and in August 2009 we issued an additional $125 million principal amount of our 10.25% senior notes due 2014.

See Note 7 to the financial statements for more information regarding our senior secured revolving credit facility, our 10.25% senior notes due 2014 and our 8.25% senior subordinated notes due 2016.

In January 2010, we completed the sale of 8 million shares of Class A common stock at a public offering at a price of $29.25 per share. The net proceeds of $224 million will be used to fund the Wolfberry acquisition and for general corporate purposes. Pending application of the proceeds for such purposes, we reduced outstanding borrowings under our senior secured revolving credit facility. Subsequent to these transactions the amount available under our credit facility will be approximately $660 million.

Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

We have also engaged in asset dispositions to generate additional cash to fund expenditures and further enhance our financial flexibility. In April 2009, we sold our DJ basin assets and related hedges for $154 million before customary closing adjustments and in July 2009, we completed the sale of our E. Texas gas gathering system for $18.4 million in cash.

Historical Cash Flows

Cash flows provided by operating activities are primarily affected by the price of crude oil and natural gas, production volumes, and changes in working capital. The decrease in net cash provided by operating activities of $197 million in 2009 compared to 2008 is primarily due to lower realized commodity sales prices in 2009 compared to 2008. The increase in net cash provided by operating activities of $171 million in 2008 compared to 2007 is primarily due to higher realized commodity sales prices and higher production volumes in 2008 compared to 2007.

Cash flows used by investing activities are primarily comprised of acquisition, exploration and development of oil and gas properties net of dispositions of oil and gas properties. The decrease in net cash used in investing activities of $1.0 billion in 2009 compared to 2008 is due to the 2008 E. Texas acquisition, a decrease in development expenditures in 2009 and the 2009 sale of our DJ basin assets and related hedges. The increase in net cash used in investing activities of $800 million in 2008 compared to 2007 is due to the 2008 E. Texas acquisition and an increase in development expenditures in 2008 compared to 2007.

Net cash used in financing activities in 2009 included the repayment of the senior secured revolving credit facility and the money market line of credit of $574 million, debt issuance costs of $24 million and dividends paid of $14 million, offset by the issuance of $450 million of 10.25% senior notes due 2014 for net proceeds of $424 million and proceeds from the sale of our E. Texas gathering system of $18 million. Net cash provided by financing activities in 2008 included net borrowings under the senior secured revolving credit facility and money market line of credit of $698 million, offset by dividends paid of $13 million and debt issuance costs of $11 million. Net cash provided by financing activities in 2007 included net borrowings under the senior secured revolving credit facility and money market line of credit of $53 million, offset by dividends paid of $13 million.

Capital Expenditures

Our capital expenditures for 2009 totaled $135 million for development and were fully funded from our $213 million operating cash flow. We also funded $13 million in acquisitions through borrowing on our senior secured credit facility and capitalized $30 million of interest. This compares to our total capital expenditures for 2008 of $398 million for development, which were fully funded from our $410 million operating cash flow. We also funded $668 million in acquisitions in 2008 through additional borrowing on our senior secured credit facility and capitalized $23 million of interest.

Excluding the acquisition of new properties, for 2010 we have established a commodity sensitive capital program that will range between $250 million and $290 million, which we expect to fund fully out of operating cash flow. We expect our 2010 capital program will allow us to increase production from 2009 levels to average 2010 production between 32,250 BOE/D and 33,000 BOE/D.

We believe that our cash flow provided by operating activities and funds available under our credit facilities will be sufficient to fund our operating and capital expenditures budget and our short-term contractual operations during 2010. However, if our revenue and cash flow decrease in the future as a result of further deterioration in economic conditions or an adverse change in commodity prices, we may have to reduce our spending levels. As we have operational control of all of our assets and we have limited drilling commitments, we believe that we have the financial flexibility to adjust our spending levels, if necessary, to meet our financial obligations.

Contractual Obligations.

Our contractual obligations as of December 31, 2009 are as follows (in millions):

	Total	2010	2011	2012	2013	2014	Thereafter
Long-term debt and interest	$ 1,359.7	$ 71.9	$ 71.9	$ 437.3	$ 62.6	$ 485.7	$ 230.3
Abandonment obligations	43.5	2.8	2.8	2.9	2.9	2.8	29.3
Operating lease obligations	16.0	2.4	2.4	2.5	2.5	2.5	3.7
Drilling and rig obligations	52.1	13.9	27.7	2.1	2.1	6.3	-
Firm natural gas transportation contracts	136.8	19.7	19.7	17.9	15.7	14.8	49.0
Total	$ 1,608.1	$ 110.7	$ 124.5	$ 462.7	$ 85.8	$ 512.1	$ 312.3

Long-term debt and interest – Borrowing under our senior secured revolving credit facility and related interest may be paid before the facility's maturity date without significant penalty. Our 8.25% senior subordinated notes and related interest mature in November 2016, but are not redeemable until November 1, 2011 and are not redeemable without any premium until November 1, 2014.

Operating leases - We lease corporate and field offices in California, Colorado and Texas. Rent expense with respect to our lease commitments for the years ended December 31, 2009, 2008 and 2007 was $2.1 million, $1.7 million and $1.5 million, respectively. In 2006, we purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

Drilling obligations - We amended and restated our Utah Lake Canyon project in December 2009 and have a 14 gross well drilling commitment over the amended term (December 2009 to December 2014). Our minimum obligation under our exploration and development agreement is $14.7 million as of December 31, 2009. Also included in the table above are contractual obligations on our Piceance assets in Colorado. We must spud 120 wells by February 2011 to avoid penalties of $0.2 million per well. We expect to meet all obligations but our ability to meet this commitment depends on the capital resources available to us to fund our activities to develop these assets on the schedule required to avoid penalties or loss of related leases.

Drilling rig obligations - We are obligated in operating lease agreements for the use of four drilling rigs, one in California, one in Utah, one in the Piceance basin and one in E. Texas.

Firm natural gas transportation - We have one firm transportation contract which provides us additional flexibility in securing our natural gas supply for California operations. This allows us to potentially benefit from lower natural gas prices in the Rocky Mountains compared to natural gas prices in California. We have eight long-term transportation contracts on five different pipelines to provide us with physical access to move gas from our producing areas to various markets.

Other obligations - 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 our Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil. Gross oil production from our Uinta properties averaged approximately 2,700 Bbl/D in 2009. Please see "Item 1A. Risk Factors–We may not be able to deliver minimum crude oil volumes required by our sales contract."

In addition, Berry has signed two precedent agreements with El Paso Corporation for an average of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, Wyoming to Malin, Oregon. While it is not certain that this new line will be constructed, the expectation is that the project will proceed and be in service by 2011. A component of these agreements is currently in dispute and may result in a termination of our contracts for capacity on this pipeline in which case we will make alternative arrangements for the transportation and marketing of our production. We do not believe the termination of these contracts will result in monetary damages. Please see "Item 1A. Risk Factors– If third-party pipelines interconnected to our natural gas wells and gathering facilities become partially or fully unavailable to transport our natural gas, our results of operations and financial condition could be adversely affected."

As of December 31, 2009, the Company had a gross liability for uncertain tax benefits of $6.1 million and an additional $0.7 million of interest related to its uncertain tax positions. At this time, the Company is unable to make a reasonably reliable estimate of the timing of payments in individual years due to uncertainties in the timing of tax audit outcomes; therefore, such amounts are not included in the above contractual obligation table.

Critical Accounting Policies and Estimates.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as disclosure of contingent assets and liabilities at the date of our financial statements   Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note 1 to our financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Successful Efforts Method of Accounting. We account for our oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs, and the costs of carrying and retaining undeveloped properties, are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion. Exploratory wells that discover potentially economic reserves that are in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized as long as the additional exploratory work is under way or firmly planned. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. The evaluation of oil and gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties.

Oil and Gas Reserves. Oil and gas reserves include proved reserves, which are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Our oil and gas reserves are based on estimates prepared by independent engineering consultants. Reserve engineering is a process that requires judgment in the evaluation of all available geological, geophysical, engineering and economic data. Projected future production rates, the timing of future capital expenditures as well as changes in commodity prices, may significantly impact estimated reserve quantities. Depreciation, depletion and amortization (DD&A) expense is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. These estimates are subject to change as additional information and technologies become available. Accordingly, oil and natural gas quantities ultimately recovered and the timing of production may be substantially different than projected. Reduction in reserve estimates may result in increased DD&A expense. Changes in reserve estimates are applied on a prospective basis. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher costs fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties. Downward revisions in our estimated reserve quantities, increases in future cost estimates or depressed crude oil or natural gas prices could cause us to reduce the carrying amounts of our properties. We perform an impairment analysis of our proved properties annually, or when current events or circumstances indicate that carrying amounts may not be recoverable, by comparing the future undiscounted net revenue to the net book carrying value of the assets. An analysis of the proved properties will also be performed whenever events or changes in circumstances indicate an asset's carrying value may not be recoverable from future net revenue. Assets are grouped at the field level and, if it is determined that the net book carrying value cannot be recovered by the estimated future undiscounted cash flow, they are written down to fair value. Cash flows used in the impairment analysis are determined based on our estimates of crude oil and natural gas reserves, future crude oil and natural gas prices and costs to extract these reserves. For our unproved properties, we perform an impairment analysis annually or whenever events or changes in circumstances indicate an asset's net book carrying value may not be recoverable. These evaluations involve a significant amount of judgment since the results are based on estimated future sales prices, costs to produce these products, estimates of oil and natural gas reserves to be recovered and the timing of development.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We also enter into derivative contracts to mitigate the risk of interest rate fluctuations. The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the statement of income because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative’s fair value and any ineffective portion of the derivative instrument’s change in fair value is recognized immediately in earnings. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, time to maturity and credit risk. The values we report in our financial statements changes as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Effective January 1, 2010, we have elected to de-designate all of our commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. At December 31, 2009, Accumulated other comprehensive loss (AOCL) consisted of $97 million ($60 million after tax) of unrealized losses, representing the mark-to-market value of the Company’s cash flow hedges as of the balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such mark-to-market values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions affect earnings. The Company expects to reclassify into earnings from AOCL the frozen value related to de-designated commodity hedges during the next three years.

Income Taxes and Uncertain Tax Positions. Income taxes are provided for the tax effects of transactions reported in the financial statements and consists of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. We routinely assess the realizability of our deferred tax assets and a valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). There can be no assurance that facts and circumstances will not materially change and require us to establish deferred tax asset valuation allowances in a future period. We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. We recognize certain tax positions that meet a more-likely-than not recognition threshold. If we ultimately determine that the payment of these liabilities will be unnecessary, we will reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies.

Asset Retirement Obligations. Our asset retirement obligations (AROs) consist primarily of estimated future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of the ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted-risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capital cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas field.

Environmental Remediation Liability. We review, on a quarterly basis, our estimates of costs of the cleanup of various sites including sites in which governmental agencies have designated us as a potentially responsible party. When it is probable that obligations have been incurred and where a minimum cost or a reasonable estimate of the cost of remediation can be determined, the applicable amount is accrued. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is an estimation process that includes the judgment of management. In many cases, management's judgment is based on the advice and opinions of legal counsel and other advisers, and the interpretation of laws and regulations, which can be interpreted differently by regulators or courts of law. Our experience and the experience of other companies in dealing with similar matters influence the decision of management as to how it intends to respond to a particular matter. A change in estimate could impact our oil and gas operating costs and the liability, if applicable, recorded on our Balance Sheet.

Accounting for Business Combinations. The accounting for business combinations is complex and involves the use of significant judgment. Under the acquisition method of accounting, assets and liabilities of an acquired business are recognized at fair value. Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired may not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices, where available, appraisals, comparisons to transactions for similar assets and liabilities and the present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Electricity Cost Allocation. Our investment in our cogeneration facilities has been for the express purpose of lowering steam costs in our California heavy oil operations and securing operating control of the respective steam generation. Such cogeneration operations produce electricity and steam and use natural gas as fuel. We allocate steam costs to our oil and gas operating costs based on the conversion efficiency (of fuel to electricity and steam) of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. Electricity used in oil and gas operations is allocated at cost. A portion of the capital costs of the cogeneration facilities is allocated to DD&A-oil and gas production.

Recent Accounting Standards Updates.

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-06 "*Improving Disclosures about Fair Value Measurements.*" The ASU amends previously issued authoritative guidance and requires new disclosures and clarifies existing disclosures and is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the rollforward activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. As this requires only additional disclosures, the guidance will have no impact on our financial position or results of operations.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 3 to the financial statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts from time to time. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. In California, we benefit from lower natural gas pricing, as we are a consumer of natural gas in our operations, and elsewhere we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate and in accordance with policy established by our board of directors. Currently, our hedges are in the form of swaps and collars. However, we may use a variety of hedge instruments in the future to hedge WTI or the index gas price. The collar strike prices allow us to protect our cash flow if oil prices decline below our floor prices which range from $55.00 to $100.00 per barrel while still participating in any oil price increase up to the ceiling prices which range from $68.00 to $161.10 per barrel on the volumes indicated below. In total, we have approximately 75% and 40% of our expected 2010 and 2011 oil production, respectively, hedged in the form of swaps and collars. Our natural gas collars have a floor of from $6.00 to $6.50 per MMBtu and ceilings ranging from $7.25 to $8.90 per MMBtu. In total, we have approximately 30% and 10% of our 2010 and 2011 expected natural gas production, respectively, hedged in the form of swaps and collars. A ten dollar change in oil prices impacts our annual operating cash flow by approximately $14 million. A one dollar change in natural gas prices impacts annual operating cash flow by approximately $2 million.

The following table summarizes our commodity hedge positions as of December 31, 2009:

Term	Average Barrels Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Collars		
Full year 2010	1,000	$65.15 / $75.00
Full year 2010	1,000	$65.50 / $78.50
Full year 2010	280	$80.00 / $90.00
Full year 2010	1,000	$100.00/$161.10
Full year 2010	1,000	$100.00/$150.30
Full year 2010	1,000	$100.00/$160.00
Full year 2010	1,000	$100.00/$150.00
Full year 2010	1,000	$100.00/$158.50
Full year 2010	1,000	$70.00/$86.00
Full year 2011	270	$80.00/$90.00
Full year 2011	1,000	$55.20/$70.00
Full year 2011	1,000	$55.00/$70.50
Full year 2011	1,000	$55.00/$68.65
Full year 2011	1,000	$55.00/$68.00
Full year 2011	1,000	$55.00/$71.20
Full year 2011	1,000	$60.00/$76.00
Full year 2011	1,000	$60.00/$81.25
Full year 2012	1,000	$63.00/$82.60
Full year 2012	1,000	$63.00/$83.50
Full year 2012	1,000	$70.00/$93.00
Crude Oil Sales (NYMEX WTI) Swaps		
Full year 2010	1,000	$61.00
Full year 2010	1,000	$61.25
Full year 2010	1,000	$64.80
Full year 2010	1,000	$62.03
Full year 2010	1,000	$63.00
Full year 2010	1,000	$63.75
Full year 2010	650	$56.90
Full year 2011	500	$57.36
Full year 2011	500	$57.40
Full year 2011	500	$57.50
Full year 2011	250	$61.80

Term	Average MMBtu Per Day	Average Price
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2010	5,000	$5.73
Full year 2010	5,000	$6.02
Full year 2011	5,000	$6.89
Full year 2012	5,000	$7.16
Natural Gas Sales (NYMEX HH) Collars		
Full year 2010	2,000	$6.00/$8.60
Full year 2010	3,000	$6.00/$8.65
Full year 2010	1,000	$6.50/$8.75
Full year 2010	1,000	$6.50/$8.85
Full year 2010	2,000	$6.50/$8.90
Full year 2011	5,000	$6.00/$7.25
Full year 2012	5,000	$6.00/$7.70
Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis Swaps		
Full year 2010	2,500	$0.415
Full year 2011	2,500	$0.460
Full year 2012	2,500	$0.440
Natural Gas Sales (NYMEX HH TO NGPL) Basis Swaps		
Full year 2010	2,000	$0.49
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2010	2,000	$0.38
Full year 2010	2,500	$0.345
Full year 2011	2,500	$0.325
Full year 2012	2,500	$0.320
Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
Full year 2010	2,000	$1.05
Full year 2010	3,000	$1.00

We generally utilize NYMEX WTI based derivatives to hedge cash flows from our California oil sales. Our oil sales contracts with multiple refiners are primarily based on the field posting prices. There is a high correlation between WTI and the field posting prices which have historically allowed us to utilize hedge accounting. As there is a ready market for our crude oil in California, we do not believe the loss of any particular refiner impacts the probability that our hedged forecasted transactions will occur. We generally hedge our natural gas at the basis location that corresponds to the sale.

While we have historically designated the majority of our hedges as cash flow hedges, we have not elected hedge accounting on certain of our crude oil and natural gas hedges. During the twelve months ended December 31, 2009, we recorded a gain of $6.5 million under the caption "Gain (loss) on derivatives" related to hedges for which we either did not elect hedge accounting or which no longer qualified for hedge accounting. In conjunction with the sale of the DJ basin assets, during the first quarter of 2009, we concluded that the forecasted transaction in certain of our hedging relationships was not probable of occurring. As such, we reclassified a gain of $14.3 million from AOCL to the statement of income under the caption "Gain (loss) on derivative." "Gain (loss) on derivatives" included a loss for cash settlements of $7.6 million and a gain for the change in fair value of $0.3 million on hedges for which we have not elected hedge accounting. Additionally, a portion of the change in fair value for hedges that we have designated as cash flow hedges may impact our income as our sales price is not perfectly correlated with our hedges. We recognized an unrealized net loss of $0.5 million on the statement of income under the caption "Gain (loss) on derivatives" for the twelve months ended December 31, 2009, as a result of ineffectiveness. During the first quarter of 2009, we entered into natural gas derivatives on behalf of the purchaser of our DJ assets. We did not elect hedge accounting for these hedges and recorded an unrealized net loss of $0.5 million on the statement of income under the caption "(Loss) income from discontinued operations, net of taxes."

We have entered into interest rate hedges as shown below to swap the floating rate under our senior secured credit facility (LIBOR) for a fixed interest rate. These interest rate swaps have been designated as cash flow hedges.

Hedge Term	Notional Amount $MM	Fixed Rate
4/1/2009 – 6/30/2012	100	4.74%
4/15/2009 – 7/15/2012	100	1.99%
9/15/2009 – 7/15/2012	50	2.31%

The related cash flow impact of all of our hedges is reflected in cash flows from operating activities. At December 31, 2009, our net fair value of derivative liability was $97.4 million as compared to a net fair value asset of $185.9 million at December 31, 2008 which reflects increases in commodity prices. Based on NYMEX strip pricing as of December 31, 2009, we expect to pay cash under the existing derivatives of $21.7 million during the next twelve months. At December 31, 2009, AOCL consisted of $60.4 million, net of tax, of unrealized losses from our crude oil and natural gas swaps and collars that qualified for hedge accounting treatment. Deferred net losses recorded in AOCL at December 31, 2009 and subsequent mark-to-market changes in the underlying hedging contracts are expected to be reclassified to earnings in the same period that the forecasted transaction impacts earnings.

Based on NYMEX futures prices as of December 31, 2009 (WTI $85.13; HH $6.31), we would expect to receive payments over the remaining term of our crude oil and natural gas hedges in place as follows:

	12/31/09 NYMEX Futures	Impact of percent change in futures prices on pretax future cash (payments) and receipts -40%	-20%	+20%	+40%
Average WTI Futures Price (2010 – 2012)	$ 85.13	$ 51.08	$ 68.10	$ 102.16	$ 119.18
Average HH Futures Price (2010 – 2012)	6.31	3.79	5.05	7.57	8.83
Crude Oil gain/(loss) (in millions)	$ (78.3)	$ 183.5	$ 53.9	$ (233.5)	$ (367.0)
Natural Gas gain/(loss) (in millions)	(0.3)	38.3	21.9	(3.7)	(16.4)
Total	$ (78.6)	$ 221.8	$ 75.8	$ (237.2)	$ (383.4)
Net pretax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2010 (WTI $81.06; HH $6.01)	$ (21.7)	$ 174.9	$ 73.3	$ (111.6)	$ (184.0)
2011 (WTI $85.51; HH $6.42)	(54.0)	30.2	(1.9)	(115.0)	(177.9)
2012 (WTI $87.83)	(2.9)	16.7	4.4	(10.6)	(21.5)
Total	$ (78.6)	$ 221.8	$ 75.8	$ (237.2)	$ (383.4)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued, in a public offering, $200 million principal amount of 8.25% senior subordinated notes due 2016. In May 2009, we issued, in a public offering, $325 million of 10.25% senior notes due 2014. In August 2009, we issued, in a public offering, an additional $125 million of 10.25% senior notes due 2014. At December 31, 2009, total long-term debt outstanding was $1.0 billion. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 2.25% to 3.0% plus the credit facility's margin through July 15, 2012. Based on December 31, 2009 credit facility borrowings, a 1% change in interest rates, including our interest rate hedges, would have an annualized $1.0 million after tax impact on our financial statements.

In June 2006 and July 2006 we entered into five year interest rate swaps for a fixed rate of approximately 5.5% on $100 million of our outstanding borrowings under our credit facility. These interest rate swaps have been designated as cash flow hedges. In 2008, $50 million of these interest rate swaps were extended one year, resulting in a fixed rate of approximately 4.8%. In 2008 we also entered into three year interest rate swaps for a fixed rate of approximately 2.2% on an additional $275 million of our outstanding borrowings under our credit facility for three years beginning on April 15 and September 15, 2009. These interest rate swaps have been designated as cash flow hedges. As of December 31, 2008, we had a total of $575 million of fixed rate positions averaging 4.8% resulting from the $200 million of 8.25% senior subordinated notes and $375 million of interest rate swaps for a fixed rate of approximately 2.2%.

During 2009, we entered into three year interest rates swaps for a fixed rate of approximately 2.1% on an additional $150 million of our outstanding borrowings under our credit facility beginning on April 15 and December 15, 2009. These interest rate swaps have been designated as cash flow hedges. As a result of these 2009 hedge contracts, we have a total of $900 million of fixed rate positions averaging 7.8%.

Effective January 1, 2010, we have elected to de-designate all of our commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. At December 31, 2009, AOCL consisted of $97 million ($60 million after tax) of unrealized losses, representing the mark-to-market value of the Company's cash flow hedges as of the balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such mark-to-market values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions affect earnings. The Company expects to reclassify into earnings from AOCL the frozen value related to de-designated commodity hedges during the next three years.

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Item 8. Financial Statements and Supplementary Data

Financial statement schedules have been omitted since they are either not required, are not applicable, or the required information is shown in the financial statements and related notes.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Berry Petroleum Company:

In our opinion, the financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Berry Petroleum Company at December 31, 2009 and 2008, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the financial statements, the Company changed the manner in which it accounts for recurring fair value measurements of financial instruments in 2008. As discussed in Note 9 to the financial statements, the Company changed the manner in which it accounts for earnings per share in 2009.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Denver, Colorado
February 25, 2010

BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2009 and 2008
(In Thousands, Except Share Information)

ASSETS	2009	2008
Current assets:		
Cash and cash equivalents	$ 5,311	$ 240
Short-term investments	66	66
Accounts receivable, net of allowance for doubtful accounts of $38,508 and $38,511, respectively	74,337	65,873
Deferred income taxes	5,623	-
Fair value of derivatives	11,527	111,886
Prepaid expenses and other	6,612	11,015
Total current assets	103,476	189,080
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,106,385	2,254,425
Fair value of derivatives	735	79,696
Other assets	29,539	19,182
	$ 2,240,135	$ 2,542,383
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 63,096	$ 119,221
Revenue and royalties payable	25,878	34,416
Accrued liabilities	29,320	34,566
Line of credit	-	25,300
Income taxes payable	-	187
Fair value of derivatives	33,843	1,445
Deferred income taxes	-	45,490
Total current liabilities	152,137	260,625
Long-term liabilities:		
Deferred income taxes	237,161	270,323
Senior secured revolving credit facility	372,000	931,800
8¼% Senior subordinated notes due 2016	200,000	200,000
10¼% Senior notes due 2014, net of unamortized discount of $13,456 and $0, respectively	436,544	-
Asset retirement obligation	43,487	41,967
Other long-term liabilities	19,711	5,921
Fair value of derivatives	75,836	4,203
	1,384,739	1,454,214
Commitments and contingencies (Note 13)		
Shareholders' equity:		
Preferred stock, $0.01 par value, 2,000,000 shares authorized; no shares outstanding	-	-
Capital stock, $0.01 par value:		
Class A Common Stock, 100,000,000 shares authorized; 42,952,499 shares issued and outstanding (42,782,365 in 2008)	430	427
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899)	18	18
Capital in excess of par value	89,068	79,653
Accumulated other comprehensive (loss) income	(60,372)	113,697
Retained earnings	674,115	633,749
Total shareholders' equity	703,259	827,544
	$ 2,240,135	$ 2,542,383

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

BERRY PETROLEUM COMPANY
Statements of Income
Years ended December 31, 2009, 2008 and 2007
(In Thousands, Except Per Share Data)

	2009	2008	2007
REVENUES			
Sales of oil and gas	$ 506,691	$ 649,248	$ 433,208
Sales of electricity	36,065	63,525	55,619
Gas marketing	22,806	35,750	-
Gain (loss) on derivatives	6,514	(213)	13
Gain (loss) on sale of assets	826	(1,297)	54,173
Interest and other income, net	1,810	3,504	4,414
	574,712	750,517	547,427
EXPENSES			
Operating costs - oil and gas production	156,612	188,758	130,940
Operating costs - electricity generation	31,400	54,891	45,980
Production taxes	18,144	26,876	14,651
Depreciation, depletion & amortization - oil and gas production	139,919	125,595	82,861
Depreciation, depletion & amortization – electricity generation	3,681	2,812	3,568
Gas marketing	21,231	32,072	-
General and administrative	49,237	54,279	39,663
Interest	49,923	23,942	15,069
Extinguishment of debt	10,823	-	-
Dry hole, abandonment, impairment and exploration	5,425	10,543	8,351
Bad debt expense	-	38,665	-
	486,395	558,433	341,083
Income before income taxes	88,317	192,084	206,344
Provision for income taxes	28,349	70,308	79,060
Income from continuing operations	59,968	121,776	127,284
(Loss) income from discontinued operations, net of tax	(5,938)	11,753	2,644
Net income	$ 54,030	$ 133,529	$ 129,928
Basic net income from continuing operations per share	1.31	2.70	2.85
Basic net (loss) income from discontinued operations per share	(0.13)	0.26	0.06
Basic net income per share	$ 1.18	$ 2.96	$ 2.91
Diluted net income from continuing operations per share	1.30	2.66	2.81
Diluted net (loss) income from discontinued operations per share	(0.13)	0.26	0.06
Diluted net income per share	$ 1.17	$ 2.92	$ 2.87

Statements of Comprehensive Income
Years Ended December 31, 2009, 2008 and 2007
(In Thousands)

	2009	2008	2007
Net income	$ 54,030	$ 133,529	$ 129,928
Unrealized gains (losses) on derivatives, net of income tax of $125,840, $96,546, and ($66,627), respectively	205,318	157,522	(99,941)
Reclassification of realized (losses) gains on derivatives included in net income, net of income tax of ($19,153), $47,119 and ($524), respectively	(31,249)	76,879	(786)
Comprehensive income	$ 228,099	$ 367,930	$ 29,201

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

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BERRY PETROLEUM COMPANY
Statements of Shareholders' Equity
Years Ended December 31, 2009, 2008 and 2007
(In Thousands, Except Per Share Data)

	Class A	Class B	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
Balances at January 1, 2007	$ 421	$ 18	$ 50,166	$ 397,072	$ (19,977)	$ 427,700
Stock-based compensation (484,451 shares)	4	-	12,930	-	-	12,934
Tax impact of stock option exercises	-	-	3,049	-	-	3,049
Deferred director fees - stock compensation	-	-	445	-	-	445
Cash dividends declared - $0.30 per share, including RSU dividend equivalents	-	-	-	(13,292)	-	(13,292)
Adoption of authoritative accounting guidance regarding uncertainty in income taxes	-	-	-	(63)	-	(63)
Change in fair value of derivatives	-	-	-	-	(100,727)	(100,727)
Net income	-	-	-	129,928	-	129,928
Balances at December 31, 2007	425	18	66,590	513,645	(120,704)	459,974
Stock-based compensation (199,363 shares)	2	-	11,684	-	-	11,686
Tax impact of stock option exercise	-	-	938	-	-	938
Deferred director fees – stock compensation	-	-	441	-	-	441
Cash dividends declared - $0.30 per share, including RSU dividend equivalents	-	-	-	(13,425)	-	(13,425)
Change in fair value of derivatives	-	-	-		234,401	234,401
Net income	-	-	-	133,529	-	133,529
Balances at December 31, 2008	427	18	79,653	633,749	113,697	827,544
Stock-based compensation (170,134 shares)	3	-	6,750	-	-	6,753
Tax impact of stock option exercises	-	-	(98)	-	-	(98)
Deferred director fees - stock compensation	-	-	2,763	-	-	2,763
Cash dividends declared - $0.30 per share, including RSU dividend equivalents	-	-	-	(13,664)	-	(13,664)
Change in fair value of derivatives	-	-	-	-	(174,069)	(174,069)
Net income	-	-	-	54,030	-	54,030
Balances at December 31, 2009	$ 430	$ 18	$ 89,068	$ 674,115	$ (60,372)	$ 703,259

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

BERRY PETROLEUM COMPANY
Statements of Cash Flows
Years Ended December 31, 2009, 2008 and 2007
(In Thousands)

	2009	2008	2007
Cash flows from operating activities:			
Net income	$ 54,030	$ 133,529	$ 129,928
Depreciation, depletion and amortization	145,788	141,049	97,259
Extinguishment of debt	10,823	-	-
Amortization of debt issuance costs and net discount	6,827	1,774	774
Dry hole and impairment	14,859	9,932	12,951
Commodity derivatives	247	(108)	574
Stock-based compensation expense	8,626	9,313	8,200
Deferred income taxes	19,998	67,982	62,465
Loss (gain) on sale of asset	79	1,297	(54,173)
Other, net	(4,016)	(2,530)	2,787
Cash paid for abandonment	(1,030)	(4,607)	(1,188)
Allowance for bad debt	-	38,511	-
Change in book overdraft	(16,018)	23,984	(9,400)
(Increase) decrease in current assets other than cash, cash equivalents and short-term investments	(10,055)	10,281	(47,876)
(Decrease) increase in current liabilities other than line of credit	(17,582)	(20,838)	36,578
Net cash provided by operating activities	212,576	409,569	238,879
Cash flows from investing activities:			
Exploration and development of oil and gas properties	(134,946)	(397,601)	(285,267)
Property acquisitions	(13,497)	(667,996)	(56,247)
Capitalized interest	(30,107)	(23,209)	(18,104)
Proceeds from sale of assets	139,796	2,037	72,405
Net cash used in investing activities	(38,754)	(1,086,769)	(287,213)
Cash flows from financing activities:			
Proceeds from issuances on line of credit	387,700	404,000	395,150
Payments on line of credit	(413,000)	(393,000)	(396,850)
Proceeds from issuance of long-term debt	1,090,262	1,708,700	229,300
Payments on long-term debt	(1,215,100)	(1,021,900)	(174,300)
Debt issuance costs	(23,955)	(11,002)	(1)
Financing obligation	18,214	-	-
Dividends paid	(13,664)	(13,425)	(13,292)
Proceeds from stock option exercises	890	2,813	5,178
Excess tax (expense) benefit	(98)	938	3,049
Net cash (used in) provided by financing activities	(168,751)	677,124	48,234
Net increase (decrease) in cash and cash equivalents	5,071	(76)	(100)
Cash and cash equivalents at beginning of year	240	316	416
Cash and cash equivalents at end of year	$ 5,311	$ 240	$ 316
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest	$ 36,854	$ 15,708	$ 15,841
Income taxes paid	$ 8,769	$ 13,290	$ 6,715
Supplemental non-cash activity:			
(Decrease) increase in fair value of derivatives:			
Current (net of income taxes of ($49,914), $75,772, and ($36,562), respectively)	$ (81,439)	$ 123,628	$ (54,844)
Non-current (net of income taxes of ($56,773), $67,893, and ($30,589), respectively)	(92,630)	110,773	(45,883)
Net (decrease) increase to accumulated other comprehensive (loss) income	$ (174,069)	$ 234,401	$ (100,727)

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

BERRY PETROLEUM COMPANY
Notes to the Financial Statements

1. Summary of Significant Accounting Policies

Description of the business

Berry Petroleum Company (the Company) is an independent energy company engaged in the production, development, acquisition, exploitation and exploration of crude oil and natural gas. The Company has invested in cogeneration facilities which provide steam required for the extraction of heavy oil and which generates electricity for sale.

Basis of presentation

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

Reclassifications and error corrections

Included in the fourth quarter of 2009 are adjustments to correct the prior accounting for the Company's royalties in the amount of $3.3 million, which resulted in decreasing its sales of oil and gas and increasing its royalties payable. The year- to-date impact of the adjustment was $1.9 million. Management concluded the impact was immaterial to the current and prior periods.

In March 2008, the Company determined there was an error in computing royalties payable in prior years, accumulating to $10.5 million as of December 31, 2007. The Company concluded the error was not material to any individual prior interim or annual period (or to the projected earnings for 2008) and, therefore, the error was corrected during the first quarter of 2008, with the effect of increasing sales of oil and gas by $10.5 million and reducing royalties payable.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with a remaining maturity of three months or less to be cash equivalents. The Company's cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at December 31, 2009 and 2008 is $15.7 million and $31.8 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

Accounts receivable

Trade accounts receivable consist mainly of receivables from oil and gas purchases and joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, oil and gas receivables are collected within two months.

Allowance for doubtful accounts

The Company routinely assesses the recoverability of all material trade and other receivables to determine collectability. As of both December 31, 2009 and 2008, the Company has an allowance for doubtful accounts of $38.5 million. The 2008 amount represents the Company's November and December 2008 sales to BWOC. The Company had a long-term contract to sell all of its heavy crude oil in California for approximately $8.10 below WTI with BWOC. On December 22, 2008, Flying J, Inc. and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC each filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's production. On March 17, 2009, the Company entered into a stipulation with BWOC, terminating the contract effective as of March 16, 2009. The Company recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of that $38.5 million due from BWOC, $11.8 million represents 20 days of December 2008 crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November and the balance of December 2008 crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to the Company for damages under this contract. While the Company also has guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, the information received from the bankruptcy proceedings to date has not provided the Company with adequate data from which to make a conclusion that any amounts will be collected. The Company has entered into various agreements with other companies to sell its California oil production.

Discontinued operations

In 2009, the Company sold its DJ Basin assets, the results of operations of which, are reported as discontinued operations in the Statement of Income.

Income taxes and uncertain tax positions

Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are accounted for using the asset and liability method, which results in the recognition of deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. A valuation allowance is recognized if it is determined that deferred tax assets may not be fully utilized in future periods. Income tax positions must meet a more-likely-than-not recognition threshold to be recognized, and any potential accrued interest and penalties related to the unrecognized tax benefits are recognized within income tax expense. Uncertain tax positions are recognized in the Balance Sheet as a current or noncurrent liability, based upon the expected timing of the payment to a taxing authority.

Derivatives

The Company periodically enters into commodity derivative contracts to manage its exposure to oil and natural gas price volatility. The Company also enters into derivative contracts to mitigate the risk of interest rate fluctuations. The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, has no effect on the statement of income because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative’s fair value. Any ineffective portion of the derivative instrument’s change in fair value is recognized immediately in earnings. The estimated fair value of derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, time to maturity and credit risk. The values the Company reports in its financial statements changes as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond its control.

Prior to January 1, 2010, the Company designated most of its commodity and interest rate derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to Accumulated other comprehensive loss (AOCL). Effective January 1, 2010, the Company has elected to de-designate all of its commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively.

As a result, subsequent to December 31, 2009, the Company will recognize all gains and losses from prospective changes in commodity and interest rate derivative fair values immediately in earnings rather than deferring any such amounts in AOCL. At December 31, 2009, AOCL consisted of $97 million ($60 million after tax) of unrealized losses, representing the mark-to-market value of the Company’s cash flow hedges as of the balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such mark-to-market values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions affect earnings. The Company expects to reclassify into earnings from AOCL the frozen value related to de-designated commodity hedges during the next three years.

Oil and gas properties, buildings and equipment

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion and the related capitalized costs are reviewed quarterly. Exploratory wells that discover potentially economic reserves in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized if the well found a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The costs of development wells are capitalized whether productive or nonproductive.

Depletion of oil and gas producing properties is computed using the units-of-production method. Depreciation of lease and well equipment, including cogeneration facilities and other steam generation equipment and facilities, is computed using the units-of-production method or on a straight-line basis over estimated useful lives ranging from 10 to 20 years. Buildings and equipment are recorded at cost. Depreciation is provided on a straight-line basis over estimated useful lives ranging from 5 to 30 years for buildings and improvements and 3 to 10 years for machinery and equipment. Estimated residual salvage value is considered when determining depreciation, depletion and amortization (DD&A) rates. Changes in reserves are applied on a prospective basis.

Interest incurred on funds borrowed to finance exploration and certain acquisition and development activities is capitalized. To qualify for interest capitalization, the costs incurred must relate to the acquisition of unproved reserves, drilling of wells to prove up the reserves and the installation of the necessary pipelines and facilities to make the property ready for production. Such capitalized interest is included in oil and gas properties, buildings and equipment. Capitalized interest is added into the depreciable base of the assets and is expensed on a units-of-production basis over the life of the respective project.

In accordance with authoritative guidance, the Company groups assets at the field level and periodically reviews the carrying value of its property and equipment to test whether current events or circumstances indicate such carrying value may not be recoverable. If the tests indicate that the carrying value of the asset is greater than the estimated future undiscounted cash flows to be generated by such asset, then an impairment adjustment needs to be recognized. Such adjustment consists of the amount by which the carrying value of such asset exceeds its fair value. The Company generally measures fair value by considering sale prices for similar assets or by discounting estimated future cash flows from such asset using an appropriate discount rate. Considerable management judgment is necessary to estimate the fair value of assets, and accordingly, actual results could vary significantly from such estimates. When assets are sold, the applicable costs and accumulated depreciation and depletion are removed from the accounts and any gain or loss is included in income. Expenditures for maintenance and repairs are expensed as incurred.

Asset retirement obligations

Asset retirement obligations (ARO) relate to future costs associated with plugging and abandonment of oil and gas wells, removal of equipments and facilities from leased acreage and returning such land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when the asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period through charges to depreciation, depletion and amortization expense, and the capitalized cost is depleted on a units-of-production basis over the proved developed reserves of the related asset. Revisions to estimated retirement obligations result in adjustments to the related capitalized asset and corresponding liability.

Accrued liabilities

Accrued liabilities consist primarily of accrued property taxes, accrued interest and accrued payroll costs. Accrued property taxes were $8.3 million and $13.5 million as of December 31, 2009 and 2008, respectively. Accrued interest was $6.9 million and $8.4 million as of December 31, 2009 and 2008, respectively. Accrued payroll costs were $8.2 million and $8.4 million as of December 31, 2009 and 2008, respectively.

Revenue recognition

Revenues associated with sales of crude oil, natural gas, electricity and natural gas marketing are recognized when delivery has occurred and title has transferred, and if the collectability of the revenue is probable. The electricity and natural gas the Company produces and uses in its operations are not included in revenues. Revenues from crude oil and natural gas production from properties in which the Company has an interest with other producers are recognized on the basis of its net working interest (entitlement method). Revenues are derived from gas marketing sales which represent excess capacity on the Rockies Express pipeline which the Company uses to market natural gas for its working interest partners.

Electricity cost allocation

The Company owns three cogeneration facilities. Its investment in cogeneration facilities has been for the express purpose of lowering steam costs in its heavy oil operations and securing operating control of the respective steam generation. Cogeneration, also called combined heat and power (CHP), extracts energy from the exhaust of a turbine that would otherwise be wasted, to produce steam. Such cogeneration operations produce electricity and steam. The Company allocates steam costs to its oil and gas operating costs based on the conversion efficiency of the cogeneration facilities plus certain direct costs in producing steam. Electricity revenue represents sales to the utilities. Electricity used in oil and gas operations is allocated at cost. A portion of the capital costs of the cogeneration facilities is allocated to DD&A-oil and gas production. Electricity consumption included in oil and gas operating costs for the years ended December 31, 2009, 2008 and 2007 was $2.8 million, $5.8 million and $5.0 million, respectively.

Transportation costs

Transportation costs, consisting primarily of natural gas transportation costs, are included in either "Operating costs - oil and gas production" or "Operating costs - electricity generation," as applicable. Natural gas transportation costs included in Operating costs - oil and gas production were $15.2 million, $9.5 million and $1.2 million for 2009, 2008 and 2007, respectively. Natural gas transportation costs included in Operating costs - electricity generation were $2.8 million, $7.2 million and $6.7 million for 2009, 2008 and 2007, respectively. Additionally, the transportation costs in Uinta were $0.2 million, $0.2 million and $1.4 million in 2009, 2008 and 2007, respectively.

Stock-based compensation

The Company recognizes the grant date fair value of stock options and other stock based compensation issued in the statement of income. Expense is recognized on a straight-line basis over the employee’s requisite service period (generally the vesting period of the award).

Earnings (loss) per share

Basic earnings (loss) per share is computed by dividing net earnings (loss) attributable to common stock by the weighted average number of common shares outstanding during each period. Under the treasury stock method, diluted earnings (loss) per share is computed by dividing net earnings (loss) adjusted for the effects of potential common shares.

Related party transactions

In December 2007, the Company accepted a tender issued by Bakersfield Fuel & Oil Company (BFO) to purchase all of its shares in BFO for $2.9 million. These proceeds are reflected in the “Proceeds from sale of assets” line on the Statements of Cash Flows and in the “Gain on sale of assets” line on the Statements of Income. Mr. Thomas Jamieson is a Director of Berry Petroleum Company and a director and the controlling stockholder of BFO. The tender was made to all shareholders of BFO other than Mr. Jamieson and his affiliates. The Corporate Governance and Nominating Committee, with input from the Audit Committee, approved this transaction.

Equity method investments

The Company owns interests in two entities which serve to gather and transport natural gas in the Company’s Lake Canyon and Brundage Canyon fields. The Company owns less than 50% interest in both entities and these interests are accounted for using the equity method. The Company’s net investment in these entities is included under the caption “Other assets” on its Balance Sheet.

Impact of recently issued accounting standard updates

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-06 "*Improving Disclosures about Fair Value Measurements.*" The ASU amends previously issued authoritative guidance and requires new disclosures and clarifies existing disclosures and is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the rollforward activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. As this requires only additional disclosures, the guidance will have no impact on the Company's financial position or results of operations.

2. Fair Value Measurement

In September 2006, authoritative guidance was issued that defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The Company adopted this guidance as of January 1, 2008 for all financial and nonfinancial assets and liabilities recognized or disclosed at fair value on a recurring basis. The Company has also adopted the authoritative guidance as it relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis as of January 1, 2009 pursuant to the authoritative guidance issued by the FASB in February 2008. The adoption of the authoritative guidance did not have a material impact on the financial statements for the years ended December 31, 2009 or 2008.

The authoritative guidance establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

A financial instrument's categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. Oil swaps, natural gas swaps and interest rate swaps are valued using internal models which are based on active market data and are classified within Level 2 of the valuation hierarchy. Derivatives that are valued based upon models with significant unobservable market inputs (primarily volatility), and that are normally traded less actively are classified within Level 3 of the valuation hierarchy. The Company determines the value of option contracts utilizing industry-standard option pricing models based on inputs that are either readily available in public markets, can be derived from information available in publicly quoted markets, or are quoted by financial institutions that trade these contracts. In situations where the Company obtains inputs via quotes from financial institutions, it verifies the reasonableness of these quotes via similar quotes from another financial institution as of each date for which financial statements are prepared. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps.

The following tables set forth by level within the fair value hierarchy the Company's assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2009 and 2008.

Assets and liabilities measured at fair value on a recurring basis

December 31, 2009 (in millions)	Total carrying value on the Balance Sheet	Level 2	Level 3
Commodity derivative liability	$ (88.5)	$ (62.5)	$ (26.0)
Interest rate swaps liability	(8.9)	(8.9)	-
Total liabilities at fair value	$ (97.4)	$ (71.4)	$ (26.0)

December 31, 2008 (in millions)	Total carrying value on the Balance Sheet	Level 2	Level 3
Commodity derivative asset	198.4	25.9	172.5
Interest rate swaps liability	(12.5)	(12.5)	-
Total assets at fair value	185.9	13.4	172.5

Changes in Level 3 fair value measurements

The table below includes a rollforward of the Balance Sheet amounts (including the change in fair value) for financial instruments classified by us within Level 3 of the valuation hierarchy. When a determination is made to classify a financial instrument within Level 3 of the valuation hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

(in millions)	Twelve months ended December 31, 2009	Twelve months ended December 31, 2008
Fair value asset (liability), beginning of period	$ 172.5	$ (194.3)
Total realized and unrealized (losses) gains included in Gain (loss) on derivatives	(1.0)	0.4
Purchases, sales and settlements, net	(200.9)	366.4
Transfers in and/or out of Level 3	3.4	-
Fair value (liability) asset, end of period	(26.0)	172.5
Total unrealized (losses) gains included in income related to financial assets and liabilities still on the balance sheet at December 31, 2009 and 2008	$ (0.1)	$ -

The $3.4 million of transfers out of Level 3 for the year ended December 31, 2009 represent crude oil collars that were converted to crude oil swaps during the first quarter of 2009.

For further discussion related to the Company's derivatives see Note 3 to the financial statements.

Fair Market Value of Financial Instruments

The Company used various assumptions and methods in estimating the fair values of its financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of the Company's credit facilities approximated fair value, because the interest rates on the credit facilities are variable. The fair values of the 8.25 % senior subordinated notes due 2016 and the 10.25 % senior notes due 2014 were estimated based on quoted market prices. The fair values of the Company's derivative instruments and other investments are discussed above.

(in millions)	Carrying Amount	Estimated Fair Value
	As of December 31, 2009	
Line of credit	$ -	$ -
Senior secured revolving credit facility	372	372
8.25 % Senior subordinated notes due 2016	200	196
10.25% Senior notes due 2014	437	487
	$ 1,009	$ 1,055

(in millions)	Carrying Amount	Estimated Fair Value
	As of December 31, 2008	
Line of credit	$ 25	$ 25
Senior secured revolving credit facility	932	932
8.25 % Senior subordinated notes due 2016	200	116
	$ 1,157	$ 1,073

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

In December 2009, subsequent to the approval of the Company's capital budget, the Company recorded a $4.2 million impairment charge related to the write down of a drilling rig to its fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, operational costs, and a risk-adjusted discount rate. The fair value measurement was based on Level 3 inputs. The fair value of the drilling rig on December 31, 2009 was $3.3 million.

3. Hedging

To minimize the effect of a downturn in oil and gas prices and protect the Company's profitability and the economics of its development plans, the Company enters into crude oil and natural gas hedge contracts from time to time. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. The Company benefits from lower natural gas pricing as it is a consumer of natural gas in its California operations. In the Rocky Mountains and E. Texas the Company benefits from higher natural gas pricing. The Company has hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate in accordance with policy established by its Board of Directors. Currently, the hedges are in the form of swaps and collars. However, the Company may use a variety of hedge instruments in the future to hedge WTI or the index gas price. The Company also utilizes interest rate derivatives to protect against changes in interest rates on its floating rate debt.

At December 31, 2009, the net fair value derivative liability was $97.4 million as compared to a net fair value asset of $185.9 million at December 31, 2008 which reflects changes in commodity prices and interest rates. Based on NYMEX strip pricing as of December 31, 2009, the Company expects to make hedge payments under the existing derivatives of $21.7 million during the next twelve months.

At December 31, 2009, AOCL consisted of $(60.4) million, net of tax, of unrealized losses from crude oil and natural gas swaps and collars that qualified for hedge accounting treatment at December 31, 2009, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such mark-to-market values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in the same period that the forecasted transactions impact earnings.

The related cash flow impact of all of the Company's hedges is reflected in cash flows from operating activities.

The Company presents its derivative assets and liabilities on its Balance Sheets on a net basis. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with a counterparty to a derivative contract. The Company uses these agreements to manage and reduce its potential counterparty credit risk.

The following table disaggregates the Company's net derivative assets and liabilities into gross components on a contract-by-contract basis before giving effect to master netting arrangements. Finally, the Company identifies the line items on its Balance Sheets in which these fair value amounts are included. The gross asset and liability values in the table below are segregated between those derivatives designated in qualifying hedge accounting relationships and those not designated in hedge accounting relationships. The Company uses the end of period accounting designation to determine the classification for each derivative position.

	As of December 31, 2009			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity – Oil	Current assets	$ 14.2	Current liability	$ 30.8
Commodity – Natural Gas	Current assets	1.3		
Commodity – Oil			Long term liabilities	74.1
Commodity – Natural Gas	Long term assets	0.4		
Commodity – Natural Gas	Current liability	0.2		
Commodity – Natural Gas	Long term liabilities	1.2		
Interest rate contracts	Long term assets	0.3	Current assets	3.5
Interest rate contracts			Current liabilities	2.7
Interest rate contracts			Long term liabilities	3.0
Total derivatives designated as hedging instruments under authoritative guidance		17.6		114.1
Commodity – Natural Gas		-	Current assets	0.4
Commodity – Natural Gas		-	Current liabilities	0.5
Total derivatives not designated as hedging instruments under authoritative guidance		-		0.9
Total Derivatives		$ 17.6		$ 115.0

The tables below summarize the Statement of Income impacts of the Company's derivative instruments for the twelve months ending December 31, 2009 (in millions):

Derivatives cash flow hedging relationships	Amount of Gain (Loss) Recognized in AOCL on Derivative(Effective portion)	Location of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Amount of Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Location of Gain (loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Amount of Gain (Loss) Recognized in Income of Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
Commodity - Oil	$ (222.3)	Sales of oil and gas	$ 53.9	Sales of oil and gas	$ -
Commodity - Natural Gas	(18.6)	Sales of oil and gas	11.1	Gain (loss) on derivatives	13.7
Interest rate	8.8	Interest expense	(7.0)	Gain (loss) on derivatives	-
Total	$ (232.1)		$ 58.0		$ 13.7

Amount of Gain or (Loss) Recognized in Income on Derivatives not designated as Hedging Instruments under authoritative guidance as of twelve months ending December 31, 2009:

Derivatives not designated as Hedging Instruments under authoritative guidance	Location of Gain (Loss) Recognized in Income on Derivative	Amount of Gain (Loss) Recognized in Income on Derivatives not designated as Hedging Instruments under authoritative guidance
Commodity – Oil	Gain (loss) on derivatives	$ (6.7)
Commodity - Natural Gas	Gain (loss) on derivatives	(0.5)
Commodity - Natural Gas	(Loss) income from discontinued operations, net of taxes	(0.5)
Total Derivatives		$ (7.7)

During the first quarter of 2009, the Company converted oil collars for 6,000 Bbl/D for the full year 2010 into swaps for the same volumes with swap prices ranging from $61.00 to $64.80.

The Company generally utilizes NYMEX WTI based derivatives to hedge cash flows from its California oil sales. The Company's oil sales contracts with multiple refiners are primarily based on the field posting prices. There is a high correlation between WTI and the field posting prices which allowed us to utilize hedge accounting. As there is a ready market for the Company's crude oil in California, the Company does not believe the loss of any particular contract impacts the probability that its hedged forecasted transactions will occur. The Company generally hedges its natural gas at the basis location that corresponds to the forecasted sale.

While the Company designates the majority of its hedges as cash flow hedges, it has not elected hedge accounting on certain of its crude oil and natural gas hedges. During the twelve months ended December 31, 2009, the Company recorded $6.5 million under the caption "Gain (loss) on derivatives" related to hedges for which it either did not elect hedge accounting or which no longer qualified for hedge accounting. In conjunction with the sale of the DJ basin assets, during the first quarter of 2009, the Company concluded that the forecasted transaction in certain of its hedging relationships was not probable of occurring. As such, the Company reclassified a gain of $14.3 million from AOCL to the Statement of Income under the caption "Gain (loss) on derivatives." "Gain (loss) on derivatives" includes a loss for cash settlements of $7.6 million and a gain for the change in fair value of $0.3 million on hedges for which the Company has not elected hedge accounting. Additionally, a portion of the change in fair value for hedges that was designated as cash flow hedges may impact the Company's income as the sales price is not perfectly correlated with the Company's hedges. The Company recognized an unrealized net loss of $0.5 million on the Statement of Income under the caption "Gain (loss) on derivatives" for the twelve months ended December 31, 2009, respectively, as a result of ineffectiveness. During the first quarter of 2009, the Company entered into natural gas derivatives on behalf of the purchaser of its DJ assets. The Company did not elect hedge accounting for these hedges and recorded an unrealized net loss of $0.5 million on the Statement of Income under the caption "(Loss) income from discontinued operations, net of taxes."

The Company's hedge contracts have been executed primarily with counterparties that are party to its senior secured revolving credit facility.

Neither the Company nor its counterparties are required to post collateral in connection with its derivative positions and netting agreements are in place with each of the Company's counterparties allowing the Company to offset its commodity derivative asset and liability positions. The credit rating of each of these counterparties was AA-/Aa2, or better as of December 31, 2009. The Company's derivatives are held with a small number of counterparties and as of December 31, 2009, the Company's largest three counterparties accounted for 76% of the value of its total derivative positions.

As of December 31, 2009, the Company had the following commodity hedges:

	2010	2011	2012
Oil Bbl/D:	14,930	9,020	3,000
Natural Gas MMBtu/D:	19,000	10,000	10,000

For further discussion related to the fair value of the Company's derivatives see Note 2 to the financial statements.

4. Asset Retirement Obligations (AROs)

The following table summarizes the change in abandonment obligation for the years ended December 31 (in thousands):

	2009	2008
Beginning balance at January 1	$ 41,967	$ 36,426
Liabilities incurred	1,407	4,686
Liabilities settled	(1,030)	(4,607)
Disposition of assets	(2,752)	-
Revisions in estimated liabilities	-	2,006
Accretion expense	3,895	3,456
Ending balance at December 31	$ 43,487	$ 41,967

The ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company’s oil and gas properties. Inherent in the fair value calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

5. Acquisitions and Divestitures

During the twelve months ended December 31, 2009, the Company completed acquisitions totaling $13.5 million. In June 2009, the Company acquired property near McKittrick, California, the deep rights to one of the leases in its Darco property in E. Texas, and additional interests in its Piceance Garden Gulch assets.

On July 17, 2009, the Company completed the financing of its E. Texas gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term gas gathering agreements for the E. Texas production which contained an embedded lease. The transaction was treated as a financing obligation. Accordingly, the net book value of the property of $16.7 million will be depreciated over the remaining useful life of the asset and the cash received of $18.4 million was recorded as a financing obligation. A portion of future payments will be recorded as gathering expense, a portion as interest expense and the balance as a reduction in the financing obligation. There is no minimum payment required under these agreements.

On March 3, 2009, the Company entered into an agreement to sell its DJ basin assets and related hedges for $154 million before customary closing adjustments. The closing date of the sale of the assets was April 1, 2009. The Company recorded a pre-tax impairment loss of $9.6 million related to the sale, which is aggregated within the $5.9 million “(Loss) income from discontinued operations, net of taxes” on its Statement of Income for the twelve months ended December 31, 2009.

(Loss) income from discontinued operations, net of tax on the accompanying statements of income is comprised of the following (in thousands):

	For the Twelve Months Ended December 31,		
	2009	2008	2007
Oil and gas revenue	$ 5,396	48,729	$ 34,192
Loss on sale of asset	(908)	-	-
Other revenue	623	2,072	1,851
Total revenue	5,111	50,801	36,043
Operating expenses	2,576	11,340	10,279
Production taxes	195	3,023	2,564
DD&A	2,188	12,642	10,829
General and administrative	388	1,074	547
Interest expense	815	2,267	2,218
Commodity derivatives	484	145	13
Dry hole, abandonment, impairment and exploration	9,637	1,772	5,306
Total expenses	16,283	32,263	31,756
(Loss) income from discontinued operations, before income taxes	(11,172)	18,538	4,287
Income tax (benefit) expense	(5,234)	6,785	1,643
(Loss) income from discontinued operations	$ (5,938)	11,753	$ 2,644

On July 15, 2008, the Company acquired a 100% working interest in natural gas producing properties on 4,500 net acres in Limestone and Harrison counties in E. Texas for approximately $668 million, including post closing adjustments of $46 million.

The unaudited pro forma results presented below for the years ended December 31, 2008 and 2007 have been prepared to give effect to the E. Texas Acquisition on the Company's results of operations under the purchase method of accounting as if it had been consummated at the beginning of each of the periods presented. The unaudited pro forma results do not purport to represent the results of operations that actually would have occurred on such date or to project the Company's results of operations for any future date or period. The pro forma results set forth below also gives effect to (1) the presentation as discontinued operations of the Company's DJ Basin assets, which were sold on April 1, 2009, and (2) the Company's implementation of authoritative guidance on determining whether instruments granted in share-based payment transactions are participating securities, which requires the revision of prior period basic and diluted earning per share data.

	Year Ended December 31, 2008	Year Ended December 31, 2007
Pro forma revenue	$ 797,261	$ 581,138
Pro forma income from operations	$ 197,196	$ 162,733
Pro forma net income	$ 125,917	$ 103,333
Pro forma basic earnings per share	$ 2.79	$ 2.34
Pro forma diluted earnings per share	$ 2.75	$ 2.30

The following is a calculation and allocation of purchase price to the E. Texas Acquisition assets and liabilities based on their relative fair values, as determined by the valuation of proved reserves and related assets as of the acquisition date:

Purchase price (in thousands):	As of December 31, 2008
Original purchase price	$ 622,356
Closing adjustments for property costs, and operating expenses in excess of revenues between the effective date and closing date	45,506
Total purchase price allocation	$ 667,862
Allocation of purchase price (in thousands):	
Oil and natural gas properties	$ 651,659(i)
Pipeline	17,277
Tax receivable	1,476
Total assets acquired	670,412
Current liabilities	(1,195)(ii)
Asset retirement obligation	(1,355)
Net assets acquired	$ 667,862

(i) Determined by reserve analysis.
(ii) Accrual for royalties payable.

In May 2007, the Company sold its non-core West Montalvo assets in Ventura County, California. The sale proceeds were approximately $61 million and the Company recognized a $52 million pretax gain on the sale, including post closing adjustments. In the fourth quarter of 2007 the Company completed the sale of a portion of its Tri-State acreage for $1.4 million.

6. Oil and Gas Properties, Buildings and Equipment

Oil and gas properties, buildings and equipment consist of the following at December 31 (in thousands):

Oil and gas:	2009	2008
Proved properties:		
Producing properties, including intangible drilling costs	$ 1,892,340	$ 1,820,609
Lease and well equipment (1)	513,961	663,610
	2,406,301	2,484,219
Unproved properties		
Properties, including intangible drilling costs	267,303	255,412
	2,673,604	2,739,631
Less accumulated depreciation, depletion and amortization	583,077	509,277
	2,090,527	2,230,354
Commercial and other:		
Land	66	810
Drilling rigs and equipment	5,333	13,166
Buildings and improvements	5,911	6,274
Machinery and equipment	26,608	22,767
	37,918	43,017
Less accumulated depreciation	22,060	18,946
	15,858	24,071
	$ 2,106,385	$ 2,254,425

(1) *Includes cogeneration facility costs.*

Suspended Well Costs

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period of greater than one year since the completion of drilling (in thousands, except number of projects):

	2009	2008	2007
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ -	$ -	$ 6,826
Capitalized exploratory well costs that have been capitalized for a period greater than one year	-	-	-
Balance at December 31	$ -	$ -	$ 6,826
Number of projects that have exploratory well costs that have been capitalized for a period of greater than one year	-	-	-

The following table reflects the net changes in capitalized exploratory well costs (in thousands):

	2009	2008	2007
Beginning balance at January 1	$ -	$ 6,826	$ 89
Additions to capitalized exploratory well costs pending the determination of proved reserves	-	-	6,826
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	-	(6,826)	-
Capitalized exploratory well costs charged to expense	-	-	(89)
Ending balance at December 31	$ -	$ -	$ 6,826

Dry hole, abandonment, impairment and exploration

In 2009 the Company had dry hole, abandonment and impairment charges of $5.2 million primarily due to a $4.2 million impairment charge related to the write-down of a rig to its fair market value (see Note 2 Fair Value Measurement). The Company incurred exploration costs in 2009 of $0.2 million compared to $0.6 million in 2008 and $0.6 million in 2007. These costs consist primarily of geological and geophysical costs.

In 2008 the Company had dry hole, abandonment, impairment and exploration charges of $10.5 million consisting primarily of $7.3 million for technical difficulties that were encountered on five wells in the Piceance basin before reaching total depth. These holes were abandoned in favor of drilling to the same bottom hole location by drilling new wells. Due to the release of its rigs the Company performed an impairment test which resulted in $2.4 million of impairment costs resulting from the impairment of one rig.

In 2007 the Company had dry hole, abandonment, impairment and exploration charges of $8.4 million that consisted primarily of a $3.3 million impairment of its Coyote Flats prospect to reflect its fair value in conjunction with the preparation of its year end reserve estimates, a $2.9 million writedown of its Bakken properties which were sold in September 2007, geological and geophysical costs of $0.6 million and other dry hole charges of $1.6 million.

7. Debt Obligations

Short-term lines of credit

In 2005, the Company completed an unsecured uncommitted money market line of credit (Line of Credit). Borrowings under the Line of Credit may be up to $30 million for a maximum of 30 days. The Line of Credit may be terminated at any time upon written notice by either the Company or the lender. In conjunction with the amendment to the Company’s senior secured credit facility, on July 15, 2008, the Line of Credit was collateralized by oil and natural gas properties representing at least 80% of the present value of the Company’s proved reserves.

At December 31, 2009 and 2008, the outstanding balance under this Line of Credit was zero and $25.3 million, respectively. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.4%. The weighted average interest rate on outstanding borrowings on the Line of Credit at December 31, 2009 and 2008 was 0% and 1.4%, respectively.

Senior secured revolving credit facility

The Company's senior secured revolving credit facility (the Agreement) has a current borrowing base and lender commitments of $938 million. The LIBOR and prime rate margins are between 2.25% and 3.0% based on the ratio of credit outstanding to the borrowing base and the annual commitment fee on the unused portion of the credit facility is 0.50%.

Covenants under the Agreement are as follows:

Total funded debt to EBITDAX (1) ratio not greater than:		
2009	2010	Thereafter
4.75	4.50	4.00

Senior secured debt to EBITDAX ratio not greater than:			
to Sep 2010	Mar 2011	Sep 2011	Thereafter
3.75	3.50	3.25	3.0

(1) Net income before interest expense, income tax expense, depreciation and amortization expense, exploration expense and non-cash items of income.

The write off of $38.5 million to bad debt expense associated with the bankruptcy of BWOC is excluded from the calculation of Net income before interest expense, income tax expense, depreciation and amortization expense, exploration expense and non-cash items of income (EBITDAX), per the Agreement.

The Agreement contains a current ratio covenant which, as defined, must be at least 1.0. The total outstanding debt at December 31, 2009 under the Agreement, as amended, and the Line of Credit was $372 million and zero, respectively, and $4 million in letters of credit have been issued under the facility, leaving $562 million in borrowing capacity available. The maximum amount available is subject to semi-annual redeterminations of the borrowing base, based on the value of the Company's proved oil and gas reserves, in April and October of each year in accordance with the lenders' customary procedures and practices. Both the Company and the banks have the bilateral right to one additional redetermination each year. The Agreement is collateralized by oil and natural gas properties representing at least 80% of the present value of the Company's proved reserves.

Second Lien Term Loan

On April 27, 2009 the Company completed a $140 million second lien term loan, with lenders from among its current lending group, with a maturity of January 16, 2013. The Company paid off the second lien term loan on May 29, 2009 from the proceeds of the issuance of its 10.25% senior notes due 2014, and wrote off $7.2 million in deferred loan fees for the year ended December 31, 2009.

10.25% senior notes due 2014

On May 27, 2009, the Company issued in a public offering $325 million principal amount of 10.25% senior notes due 2014 ($325 million Notes). Interest on the $325 million Notes is paid semiannually in June and December of each year. The $325 million Notes were issued at a discount to par value of 93.546%, and are carried on the balance sheet at their amortized cost. The deferred costs of approximately $9.5 million associated with the issuance of this debt are being amortized over the five year life of the $325 million Notes. Pursuant to the terms of the Company's senior secured revolving credit facility, the issuance of the $325 million Notes automatically reduced its borrowing base by 25 cents per dollar of Notes issued, or approximately $81 million. The Company wrote off $3.3 million of deferred loan fees during the second quarter of 2009 as a result of the decrease in its borrowing base.

On August 13, 2009, the Company issued in a public offering an additional $125 million principal amount of its 10.25% senior notes due 2014 ($125 million notes and, together with the $325 million notes, the Notes). The $125 million Notes were issued at a premium to par value of 104.75%, and are carried on the balance sheet at their amortized cost. The deferred costs of approximately $1.9 million associated with the issuance of this debt are being amortized over the five year life of the Notes. Pursuant to the terms of the Company's senior secured revolving credit facility, the issuance of the $125 million Notes automatically reduced its borrowing base by 25 cents per dollar of notes issued, or approximately $31 million. The Company wrote off $0.3 million of deferred loan fees during the third quarter of 2009 as a result of the decrease in its borrowing base.

The $125 million Notes and the previously issued $325 million Notes are treated as a single series of debt securities and are carried on the balance sheet at their combined amortized cost.

8.25% senior subordinated notes due 2016

In 2006, the Company issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Sub notes). Interest on the Sub notes is paid semiannually in May and November of each year. The deferred costs of approximately $5.2 million associated with the issuance of this debt are being amortized over the ten year life of the Sub notes.

Financial Covenants

The senior secured revolving credit facility contains restrictive covenants as described above. Under the Company's senior subordinated and senior unsecured notes as long as the interest coverage ratio (as defined) is greater than 2.5 times, the Company may incur additional debt. The Company was in compliance with all of these covenants as of December 31, 2009.

	As of December 31, 2009
Current Ratio (Not less than 1.0)	5.5
Total Funded Debt Ratio to EBITDAX (Not greater than 4.75)	3.3
Interest Coverage Ratio (Not less than 2.5)	4.2
Senior Secured Debt Ratio to EBITDAX (Not greater than 3.75)	1.2

The weighted average interest rate on the Company's total outstanding borrowings was 7.0% and 4.9% at December 31, 2009 and 2008, respectively.

8. Income Taxes

The continuing operations provision for income taxes consists of the following (in thousands):

	2009	2008	2007
Current:			
Federal	$ 2,388	$ 2,991	$ 12,676
State	(198)	5,285	5,191
	2,190	8,276	17,867
Deferred:			
Federal	28,221	56,919	52,235
State	(2,062)	5,113	8,958
	26,159	62,032	61,193
Total	$ 28,349	$ 70,308	$ 79,060

The following table summarizes the components of the total deferred tax assets and liabilities. The components of the net deferred tax liability consist of the following at December 31 (in thousands):

	2009	2008
Deferred tax asset:		
Federal benefit of state taxes	$ 6,064	$ 11,082
Credit carryforwards	27,729	33,636
Stock option costs	11,091	9,089
Derivatives	42,218	2,282
Bad debt expense	15,605	15,936
Other, net	1,807	4,312
	104,514	76,337
Deferred tax liability:		
Depreciation and depletion	(330,836)	(319,349)
Derivatives	(5,216)	(72,801)
	(336,052)	(392,150)
Net deferred tax liability	$ (231,538)	$ (315,813)

At December 31, 2009, the Company's net deferred tax assets and liabilities were recorded as a current asset of $5.6 million and a long-term liability of $237.2 million. At December 31, 2008, the Company's net deferred tax assets and liabilities were recorded as a current liability of $45.5 million and a long-term liability of $270.3 million.

Reconciliation of the continuing operations statutory federal income tax rate to the effective income tax rate follows:

	2009	2008	2007
Tax computed at statutory federal rate	35%	35%	35%
State income taxes, net of federal benefit	4	3	5
Deferred state rate impact	(4)	(1)	-
Net impact to uncertain tax positions	(2)	-	-
Other	(1)	(1)	(2)
Effective tax rate	32%	36%	38%

The Company has approximately $14 million of federal and $15 million of state (California) EOR tax credit carryforwards available to reduce future income taxes. The EOR credits will begin to expire, if unused, in 2024 and 2016 for federal and California purposes, respectively.

In June 2006, the FASB issued authoritative guidance on accounting for uncertainty in income taxes. The guidance addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. The Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. There is also guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires additional disclosures.

As of December 31, 2009, the Company had a gross liability for uncertain tax benefits of $6.1 million of which $5.2 million, if recognized, would affect the effective tax rate. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. The Company had accrued approximately $0.7 million and $1.2 million of interest related to its uncertain tax positions as of December 31, 2009 and 2008, respectively.

For the year ended December 31, 2009 the Company recognized a net benefit of approximately $4.0 million to the Statements of Income due to audit settlements and the closure of certain federal and state tax years and uncertain tax positions accruals, net of interest expense, of approximately $0.8 million.

For the year ended December 31, 2008 the Company recognized a net benefit of approximately $1.6 million to the Statements of Income due to the closure of certain federal and state tax years, offset by additional uncertain tax position accruals net of interest expense of approximately $1.9 million.

For the year ended December 31, 2007 the Company recognized a net benefit of approximately $0.6 million to the Statements of Income due to the closure of certain federal and state tax years, offset by additional uncertain tax position accruals net of interest expense of approximately $0.2 million.

The following table illustrates changes in the gross unrecognized tax benefits (in millions):

	2009	2008	2007
Unrecognized tax benefits at January 1	$ 12.0	$ 12.0	$ 14.6
(Decreases) increases for positions taken in current year	(0.1)	1.2	0.5
(Decreases) increases for positions taken in a prior year	(1.3)	0.3	(0.3)
Decreases for settlements with taxing authorities	(3.6)	-	-
Decreases for lapses in the applicable statute of limitations	(0.9)	(1.5)	(2.8)
Unrecognized tax benefits at December 31	$ 6.1	$ 12.0	$ 12.0

As of December 31, 2009, the Company remains subject to examination in the following major tax jurisdictions for the tax years indicated below:

Jurisdiction:	Tax Years Subject to Exam:
Federal	2005 – 2008
California	2005 – 2008
Colorado	2005 – 2008
Utah	2005 – 2008

9. Earnings Per Share

In June 2008, the FASB issued authoritative guidance, which clarifies that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the earnings allocation in computing basic earnings per share under the two-class method. All prior period earnings per share data presented were adjusted retrospectively to conform with the provisions of the guidance which is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years.

The following table shows the computation of basic and diluted net (loss) income per share from continuing and discontinued operations for the years ended December 31, (in thousands):

	2009	2008	2007
Net income from continuing operations	$ 59,968	$ 121,776	$ 127,284
Less: Income allocable to participating securities	1,460	1,752	1,494
Income available for shareholders	$ 58,508	$ 120,024	$ 125,790
Net (loss) income from discontinued operations	$ (5,938)	$ 11,753	$ 2,644
Less: Income allocable to participating securities	-	173	32
Loss (income) from discontinued operations available for shareholders	$ (5,938)	$ 11,580	$ 2,612
Basic earnings per share from continuing operations	$ 1.31	$ 2.70	$ 2.85
Basic (loss) earnings per share from discontinued operations	(0.13)	.26	.06
Basic earnings per share	$ 1.18	$ 2.96	$ 2.91
Dilutive earnings per share from continuing operations	$ 1.30	$ 2.66	$ 2.81
Dilutive (loss) earnings per share from discontinued operations	(0.13)	.26	.06
Basic earnings per share	$ 1.17	$ 2.92	$ 2.87
Weighted average shares outstanding - basic	44,625	44,485	44,075
Add: dilutive effects of stock options	221	578	604
Weighted average shares outstanding - dilutive	44,846	45,063	44,679

Options to purchase $1.6 million, $0.2 million and $0.0 million shares were not included in the diluted (loss) earnings per share calculation for the years ended December 31, 2009, 2008 and 2007, respectively, because their effect would have been anti-dilutive.

The adoption of the guidance issued by the FASB decreased basic earnings per share from continuing operations by $0.4 and $0.4 for the years ended December 31, 2008 and 2007, respectively, and dilutive earnings per share from continuing operations by $0.2 and $0.2 for the years ended December 31, 2008 and 2007, respectively. Basic and dilutive (loss) earnings per share from discontinued operations remained unchanged for the year ended December 31, 2008 and 2007.

10. Shareholders' Equity

Shares of Class A Common Stock (Common Stock) and Class B Stock, referred to collectively as the "Capital 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 Common Stock at the option of the holder.

Dividends

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

Dividend payments are limited by covenants in the Company's (1) credit facility to the greater of $20 million or 75% of net income, and (2) bond indenture of up to $20 million annually irrespective of its coverage ratio or net income if the Company has exhausted its restricted payments basket, and up to $10 million in the event it is in a non-payment default.

Shareholder Rights Plan

In November 1999, the Company adopted a Shareholder Rights Agreement and declared a dividend distribution of one Right for each outstanding share of Capital Stock on December 8, 1999. The plan expired on December 8, 2009. No rights were exercised under the plan.

11. Equity Incentive Compensation Plans and Other Benefit Plans

In December 1994, the Company's Board of Directors adopted the Berry Petroleum Company 1994 Stock Option Plan which was restated and amended in December 1997 and December 2001 (the 1994 Plan or Plan) and approved by the shareholders in May 1998 and May 2002, respectively. The 1994 Plan provided for the granting of stock options to purchase up to an aggregate of 3,000,000 shares of Common Stock. All options, with the exception of the formula grants to non-employee Directors, were granted at the discretion of the Compensation Committee and the Board of Directors. The term of each option did not exceed ten years from the date the options were granted. The 1994 Plan expired in December 2004, and the shareholders approved a new equity incentive plan in May 2005.

The 2005 Equity Incentive Plan (the 2005 Plan), approved by the shareholders in May 2005, provides for granting of equity compensation up to an aggregate of 2,900,000 shares of Common Stock. All equity grants are at market value on the date of grant and at the discretion of the Compensation Committee or the Board of Directors. The term of each grant did not exceed ten years from the grant date, and vesting has generally been at 25% per year for 4 years or 100% after 3 years. The 2005 Plan also allows for grants to non-employee Directors although no grants were made to non-employee directors in 2008 or 2009. The grants made to the non-employee Directors under the 2005 plan vest immediately. The Company uses a broker for issuing new shares upon option exercise.

Total compensation cost recognized in the Statements of Income was $7.7 million, $8.9 million and $8.4 million in 2009, 2008 and 2007, respectively. The tax benefit related to this compensation cost was $3.2 million, $3.8 million and $3.3 million in 2009, 2008 and 2007, respectively.

Stock Options

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model that uses the assumptions noted in the following table. Expected volatilities are based on the historical volatility of the Company's stock. The Company uses historical data to estimate option exercises and employee terminations within the valuation model; separate groups of recipients that have similar historical exercise behavior are considered separately for valuation purposes. The expected term of options granted is based on historical exercise behavior and represents the period of time that options granted are expected to be outstanding; the range given below results from certain groups of recipients exhibiting different exercise behavior. The risk free rate for periods within the contractual life of the option is based on U.S. Treasury rates in effect at the time of grant. During 2009, no options were granted.

	2009	2008	2007
Expected volatility	-	36%	32% - 33%
Weighted-average volatility	-	36%	33%
Expected dividends	-	1%	1%
Expected term (in years)	-	5	4.9 - 5.6
Risk-free rate	-	3.2%	3.4% - 4.7%

The following table summarizes information related to stock options outstanding and exercisable as of December 31, 2009:

Range of Exercise Prices	Options Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Options Exercisable	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
$7.00 - $15.00	645,100	$ 10.55	3.5	645,100	$ 10.55	3.5
$15.01 - $25.00	436,250	21.61	4.9	436,250	21.61	4.9
$25.01 - $35.00	881,051	31.87	6.5	791,475	31.81	6.5
$35.01 - $45.00	313,619	42.74	8.1	135,500	43.20	8.1
Total	2,276,020	$ 25.36	5.6	2,008,325	$ 23.53	5.6

Weighted average option exercise price information for the years ended December 31:

	2009	2008	2007
Outstanding at January 1	$ 25.16	$ 24.33	$ 20.97
Granted during the year	-	41.18	43.40
Exercised during the year	13.52	19.38	12.52
Cancelled/expired during the year	28.48	29.66	22.88
Outstanding at December 31	25.36	25.16	24.33
Exercisable at December 31	23.53	21.70	19.88

The following is a summary of stock option activity for the years ended December 31:

	2009	2008	2007
Balance outstanding, January 1	2,421,650	2,527,266	2,859,836
Granted	-	89,084	220,115
Exercised	(62,050)	(149,950)	(444,216)
Canceled/expired	(83,580)	(44,750)	(108,469)
Balance outstanding, December 31	2,276,020	2,421,650	2,527,266
Balance exercisable at December 31	2,008,325	1,842,532	1,558,780
Available for future grant	218,635	412,025	988,798
Weighted average remaining contractual life (years)	5.6	6.5	7.3
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$ -	$ 14.03	$ 13.88

As of December 31, 2009, there was $2.4 million of total unrecognized compensation cost related to stock options granted under the Plan. This cost is expected to be recognized over a weighted-average period of 1.3 years. The tax benefit realized from stock options exercised during the year ended December 31, 2009, 2008 and 2007 is $0.1 million, $1.4 million and $3.5 million, respectively.

	Stock Options		
		Years ended	
	December 31, 2009	December 31, 2008	December 31, 2007
Weighted average fair value per option granted during the year based on the Black-Scholes pricing model	$ -	$ 14.03	$ 13.88
Total intrinsic value of options exercised (in millions)	0.6	4.4	11.9
Total intrinsic value of options outstanding (in millions)	15.3	-	50.8
Total intrinsic value of options exercisable (in millions)	15.3	-	38.3

Restricted Stock Units

Under the 2005 Equity Plan, the Company began a long-term incentive program whereby restricted stock units (RSUs) are available for grant to certain employees and non-employee Directors. Granted RSUs generally vest at either 25% per year over 4 years or 100% after 3 years. Unearned compensation under the restricted stock award plan is amortized over the vesting period. During 2009 and 2008, the non-employee Directors did not receive any RSUs. The RSUs granted to the non-employee Directors are 100% vested at date of grant but are subject to a deferral election before the corresponding shares are issued of a minimum of four years or until they leave the Board of Directors or upon change of control. The Company pays cash compensation on the RSUs in an equivalent amount of actual dividends paid on a per share basis of its outstanding common stock.

The following is a summary of RSU activity for the year ended December 31, 2009:

	RSUs	Weighted Average Intrinsic Value at Grant Date	Weighted Average Contractual Life Remaining
Balance outstanding, January 1	966,198	$ 20.83	3.0 years
Granted	294,504	26.72	
Converted	(107,375)	28.98	
Canceled/expired	(46,034)	25.08	
Balance outstanding, December 31	1,107,293	$ 22.14	2.6 years

	RSUs Year ended December 31,		
	2009	2008	2007
Weighted-average grant date fair value of RSUs issued	26.72	$ 11.26	$ 42.36
Total value of RSUs vested (in millions)	2.6	0.8	2.1

The total compensation cost related to nonvested awards not yet recognized on December 31, 2009 is $12.6 million and the weighted average period over which this cost is expected to be recognized is 1.6 years.

Other Employee Benefits - 401(k) Plan

The Company sponsors a defined contribution thrift plan under section 401(k) of the Internal Revenue Code to assist all employees in providing for retirement or other future financial needs. In December 2005, the 401(k) Plan was amended whereby effective January 1, 2006, the Company’s matching contribution is $1.00 for each $1.00 contributed by the employee up to 8% of an employee's eligible compensation. The Company’s contributions to the 401(k) Plan, net of forfeitures, were $1.4 million for each of the years ended December 31, 2009, 2008 and 2007. Employees are eligible to participate in the 401(k) Plan on their date of hire and approximately 97% of the Company’s employees participated in the 401(k) Plan in 2009.

Director Deferred Compensation Plan

The Company established a non-employee director deferred stock and compensation plan to permit eligible directors, in recognition of their contributions to the Company, to receive compensation for service and to defer recognition of their compensation in whole or in part to a Stock Unit Account or an Interest Account. When the eligible director ceases to be a director, the distribution from the Stock Unit Account shall be made in shares using an established market value date. The distribution from the Interest Account shall be made in cash. The plan may be amended at any time, but not more than once every six months, by the Compensation Committee or the Board of Directors. Shares earned and deferred in accordance with the plan as of December 31, 2009, 2008 and 2007 were 124,686, 24,204 and 12,934, respectively.

Amounts allocated to the Stock Unit Account have the right to receive an amount equal to the dividends per share the Company declares as applicable. The dividend payment date and this “dividend equivalent” shall be treated as reinvested in an additional number of units and credited to their account using an established market value date. Amounts allocated to the Interest Account are credited with interest at an established interest rate.

12. Concentration of Credit Risks

Significant Customers

The Company sells oil, gas and natural gas liquids to pipelines, refineries and oil companies and electricity to utility companies. Credit is extended based on an evaluation of the customer’s financial condition and historical payment record. The Company does not believe that the loss of any one customer would impact the marketability, but it may impact the profitability of its crude oil, gas, natural gas liquids or electricity sold. Due to the possibility of refinery constraints in the Utah region, it is possible that the loss of the crude oil sales customer could impact the marketability of a portion of the Company’s Utah crude oil volumes.

In 2009, sales to three purchasers were approximately 25%, 16% and 12% of the Company’s revenue. In 2008, sales to two purchasers were approximately 60% and 11% of the Company’s revenue. In 2007, sales to one purchaser was approximately 68% of the Company’s revenue.

As of both December 31, 2009 and 2008 the Company has an allowance for doubtful accounts of $38.5 million, which represents the Company's November and December 2008 sales to BWOC. While the Company believes that it may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided the Company with any data from which to make a conclusion that any amounts will be collected.

Concentrations of Market Risk

The future results of the Company's oil and gas operations will be affected by the market prices of oil and gas. The availability of a ready market for crude oil, natural gas and liquid products in the future will depend on numerous factors beyond the Company's control, including weather, imports, proximity and capacity of oil and gas pipelines and other transportation facilities, any oversupply or undersupply of oil, gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

During 2009, the Company did not have any credit losses on the sale of oil, natural gas, natural gas liquids or hedging contracts. During 2008, the Company experienced two credit losses related to its oil and natural gas sales. Included in bad debt expense in 2008 is $0.2 million related to the bankruptcy of SemGroup and $38.5 million related to BWOC as described above. During 2007 the Company did not have any credit losses on the sale of oil, natural gas, natural gas liquids or hedging contracts.

The Company places its temporary cash investments with high quality financial institutions and limit the amount of credit exposure to any one financial institution. For the three years ended December 31, 2009, the Company has not incurred losses related to these investments.

Concentrations of Credit Risk

Derivative financial instruments that hedge the price of oil and gas and interest rate levels are generally executed with major financial or commodities trading institutions which expose us to market and credit risks and may, at times, be concentrated with certain counterparties or groups of counterparties. As of December 31, 2009, $74 million of the approximate net value of the Company's hedging positions of approximately $97 million can be attributed to one of three counterparties. While a significant portion of its hedges are with a small number of counterparties, the Company monitors each counterparty's credit rating and CDS rate. Neither the Company nor its counterparties are required to post collateral under the Company's hedging contracts.

13. Commitments and Contingencies

The Company's contractual obligations not included in its Balance Sheet as of December 31, 2009 (except Long-term debt and Abandonment obligations) are as follows (in millions):

	Total	2010	2011	2012	2013	2014	Thereafter
Long-term debt and interest	$ 1,359.7	$ 71.9	$ 71.9	$ 437.3	$ 62.6	$ 485.7	$ 230.3
Abandonment obligations	43.5	2.8	2.8	2.9	2.9	2.8	29.3
Operating lease obligations	16.0	2.4	2.4	2.5	2.5	2.5	3.7
Drilling and rig obligations	52.1	13.9	27.7	2.1	2.1	6.3	-
Firm natural gas transportation contracts	136.8	19.7	19.7	17.9	15.7	14.8	49.0
Total	$ 1,608.1	$ 110.7	$ 124.5	$ 462.7	$ 85.8	$ 512.1	$ 312.3

Operating leases

The Company leases corporate and field offices in California, Colorado and Texas. Rent expense with respect to its lease commitments for the years ended December 31, 2009, 2008 and 2007 was $2.1 million, $1.7 million and $1.5 million, respectively. In 2006, the Company purchased an airplane for business travel which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

Drilling obligations

The Company amended and restated its Utah Lake Canyon project in December 2009 and has a 14 gross well drilling commitment over the amended term (December 2009 to December 2014). The Company's minimum obligation under its exploration and development agreement is $14.7 million as of December 31, 2009. Also included above the Company has contractual obligations on its Piceance assets in Colorado. The Company must spud 120 wells by February 2011 to avoid penalties of $0.2 million per well. The Company expects to meet all obligations but its ability to meet this commitment depends on the capital resources available to the Company to fund its activities to develop these assets on the schedule required to avoid penalties or loss of related leases.

Other Commitments

On July 17, 2009, the Company closed on the financing of its E. Texas gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term gas gathering agreements for the E. Texas production which contained an embedded lease. There is no minimum payment required under these agreements. For the year ended 2009, the Company has incurred $2.0 million under the agreements.

On June 17, 2009, the Company amended its natural gas firm transportation agreement with Enbridge Pipelines providing for transportation of its gas from Tex-OK to Orange County, Florida (Zone 1). The agreement provides for minimum volume of 25,000 MMBtu/d and a maximum volume of 55,000 MMBtu/D.

The Company has two long-term firm transportation contracts that total 35,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. The Company pays a demand charge for this capacity and its own production did not completely fill that capacity. To maximize the utilization of its firm transportation, the Company bought its partners' share of the gas produced in the Piceance basin at the market rate for that area and used its excess transportation to move this gas to the sales point. The pre-tax net of its gas marketing revenue and its gas marketing expense in the Statements of Operations is $1.6 million, $3.7 million and $0 for the years ended December 31, 2009, 2008 and 2007, respectively.

In addition, Berry has signed two precedent agreements with El Paso Corporation for an average of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. While it is not certain that this new line will be constructed, the expectation is that the project will proceed and be in service by 2011. A component of these agreements is currently in dispute and may result in a termination of the contracts for capacity on this pipeline in which case the Company will make alternative arrangements for the transportation and marketing of the Company's production. The Company does not believe the termination of these contracts will result in monetary damages. Please see "Item 1A. Risk Factors– If third-party pipelines interconnected to our natural gas wells and gathering facilities become partially or fully unavailable to transport our natural gas, our results of operations and financial condition could be adversely affected."

The Company is 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 its Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil. Gross oil production from the Company's Uinta properties averaged approximately 2,700 Bbl/D in 2009. Please see "Item 1A. Risk Factors–We may not be able to deliver minimum crude oil volumes required by our sales contract."

In December 2008, Flying J, Inc., and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's California production. Included in the allowance for doubtful accounts is $38.5 million due from BWOC. Of the $38.5 million due from BWOC, $11.8 million represents 20 days of the Company's December 2008 crude oil sales, an administrative claim under the bankruptcy proceedings, and $26.7 million represents November 2008 and the balance of December 2008 crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract. The Company has guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, in the event that the claim is not fully collectible from BWOC. While the Company believes that it may recover some or all of the amounts due from BWOC, the data received from the bankruptcy proceedings to date has not provided the Company with adequate data from which to make a conclusion that any amounts will be collected.

The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material effect on its financial position, or on the results of operations or liquidity.

Certain of the Company's royalty payment calculations are being disputed. The Company believes that its royalty calculations are in accordance with applicable leases and other agreements. However, the disputed amounts that it may be required to pay are up to approximately $6 million.

In July 2009, the Company received a notice of proposed civil penalty from the Bureau of Land Management (BLM) related to the Company's alleged non-compliance during 2007 with regulations relating to the operation and position of certain valves in its Uinta basin operations. The proposed civil penalty was $69.6 million and reflects the theoretical maximum penalty amount under applicable regulations, absent mitigating factors. In 2007 the Company immediately remediated the instances of non-compliance, cooperated fully with the BLM's investigation and the Company believes no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, the Company believes this matter will be resolved by the payment of a penalty that will not exceed $2.1 million and accrued such amount in the second quarter of 2009.

During the California energy crisis in 2000 and 2001, the Company had electricity sales contracts with various utilities and a portion of the electricity prices paid to the Company under such contracts from December 2000 to March 27, 2001 has been under a degree of legal challenge since that time. It is possible that the Company may have a liability pending the final outcome of the CPUC proceedings on the matter. 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 the Company. 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.

As of December 31, 2009, the Company had a gross liability for uncertain tax benefits of $6.1 million and an additional $0.7 million of interest related to its uncertain tax positions. At this time, the Company is unable to make a reasonably reliable estimate of the timing of payments in individual years due to uncertainties in the timing of tax audit outcomes; therefore, such amounts are not included in the above contractual obligation table.

14. Subsequent Events

The Company evaluates subsequent events through the date the financial statements are issued, which for the annual period ended December 31, 2009, is February 25, 2010.

Effective January, 2010, the Company has elected to de-designate all of its commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively.

In January 2010, the Company entered into an agreement with a private seller to acquire interests in producing properties principally in the Wolfberry trend in West Texas for approximately $126 million in cash. The effective date of the transaction is January 1, 2010. Closing is expected in March 2010.

In January 2010, the Company completed the sale of 8,000,000 shares of its Class A Common Stock at $29.25 per share. Net proceeds from the sale of common stock, after deducting estimated underwriting discounts and commissions and offering expenses, was $224.3 million. Net proceeds from the offering are expected to be used to fund the planned acquisition of certain properties in the Wolfberry trend of W. Texas and for general corporate purposes. Pending the application of the proceeds for such purposes, the Company used the net proceeds to reduce outstanding borrowings under its senior secured revolving credit facility.

In February 2010, the Company entered into an agreement with a private seller to acquire interests in producing properties in the Wolfberry trend in W. Texas for approximately $14 million cash.

15. Quarterly Financial Data (Unaudited)

The following is a tabulation of unaudited quarterly operating results for 2009 and 2008 (in thousands, except per share data) and has been updated to reflect (1) the presentation as discontinued operations of the Company's natural gas assets in the Denver-Julesburg basin in Colorado (the DJ Basin assets) , and (2) the Company's implementation of authoritative guidance for determining whether instruments granted in share-based payment transactions are participating securities, which requires the revision of prior period basic and diluted earnings per share data. .

2009	Operating Revenues	Income (Loss) From Continuing Operations	Income (Loss) from Discontinued Operations	Net Income (Loss)	Basic Net Income(Loss) From Continuing Operations Per Share	Basic Net Income(Loss) From Discontinued Operations Per Share	Diluted Net Income(Loss) From Continuing Operations Per Share	Diluted Net Income(Loss) From Discontinued Operations Per Share
First Quarter	$ 145,720	$ 41,779	$ (6,781)	$ 34,998	$ 0.92	$ (0.15)	$ 0.92	$ (0.15)
Second Quarter (1)	130,265	(12,768)	(212)	(12,980)	(0.28)	-	(0.28)	-
Third Quarter	141,809	18,339	668	19,007	0.41	0.01	0.40	0.01
Fourth Quarter (2)	147,768	12,618	387	13,005	0.28	0.01	0.28	0.01
	$ 565,562	$ 59,968	$ (5,938)	$ 54,030	$ 1.31	$ (0.13)	$ 1.30	$ (0.13)
2008								
First Quarter	$ 170,824	$ 39,536	$ 3,495	$ 43,031	$ 0.88	$ 0.08	$ 0.86	$ 0.08
Second Quarter	197,532	43,712	5,429	49,141	0.97	0.12	0.95	0.12
Third Quarter	225,491	49,615	3,733	53,348	1.10	0.08	1.08	0.08
Fourth Quarter (3)	154,676	(11,087)	(904)	(11,991)	(0.24)	(0.02)	(0.24)	(0.02)
	$ 748,523	$ 121,776	$ 11,753	$ 133,529	$ 2.70	$ 0.26	$ 2.66	$ 0.26

(1) Includes an unrealized pre-tax non-cash loss on derivatives of $31.1 million, a pre-tax charge of $10.5 million for debt extinguishment costs and a liability for a regulatory compliance matter of $2.1 million.

(2) Included in the fourth quarter of 2009 are adjustments to correct the prior accounting for the Company's royalties in the amount of $3.3 million, which resulted in decreasing its sales of oil and gas and increasing its royalties payable. Management concluded the impact was immaterial to the current and prior periods. Also included in the fourth quarter of 2009 is an impairment charge of $4.2 million for the write-down of a rig.

(3) Includes $38.5 million of bad debt expense related to the allowance for bad debt taken for the bankruptcy of BWOC.

16. Supplemental Information About Oil & Gas Producing Activities (Unaudited)

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-03 "*Extractive Activities – Oil and Gas (Topic) 932.*" The ASU amends previously issued authoritative guidance. The objective of the amendments included in the ASU is to align the oil and gas reserves estimation and disclosure requirements with the requirements of the Securities and Exchange Commission (SEC). The new guidance, among other purposes, is primarily intended to provide investors with a more meaningful and comprehensive understanding of oil and gas producing activities, updating the definition of proved oil and gas reserves to indicate that entities must use the average, first-day-of-the-month price during the 12-month period before the ending date of the period covered by the report, disclosing geographical areas that represent a certain percentage of proved reserves, updating the reserve estimation requirements for changes in practice and technology that have occurred over the past several decades and requiring an entity to disclose separately the amounts and quantities for consolidated and equity method investments. The Company has applied this guidance to its Financial Statements for the year-ended December 31, 2009. The new oil and gas reserve measurement and reporting requirements were adopted for oil and gas reserves as of December 31, 2009. For accounting purposes, the new requirements constitute a change in accounting principle inseparable from a change in estimate. Prior reserve disclosures were not modified and the impact of the new requirements on our oil and gas reserves was reflected as a change in estimate. Changes in reserves estimates are applied on a prospective basis.

The following sets forth costs incurred for oil and gas property acquisition, development and exploration activities, whether capitalized or expensed (in thousands):

Property acquisitions	2009	2008	2007
Proved properties	$ 13,497	$ 667,996	$ -
Unproved properties	-	-	56,247
Development (1)	138,168	385,599	278,398
Exploration (2)	30,316	32,909	23,325
	$ 181,981	$ 1,086,504	$ 357,970

(1)Development costs include $4.9 million, $0.1 million and $1.2 million charged to expense during 2009, 2008 and 2007, respectively.

(2)Exploration costs include $0.2 million, $2.4 million and $5.2 million that were charged to expense during 2009, 2008 and 2007, respectively. Exploration costs include $30.1 million $23.2 million and $18.1 million of capitalized interest in 2009, 2008 and 2007, respectively.

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent the Company's owned interests located solely within the United States. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved developed are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

For the years ended December 31, 2009, 2008 and 2007 the Company engaged DeGolyer and McNaughton ("D&M") to estimate its proved oil and gas reserves and the future net revenue to be derived from its properties. D&M is an independent petroleum engineering consulting firm has provided consulting services throughout the world for over 70 years.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond the Company's 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 product prices or development and production expenses, may require revision of such estimates. Accordingly, oil and gas quantities ultimately recovered will vary from reserve estimates. These estimates do not include probable or possible reserves. The information provided does not represent management's estimate of its expected future cash flows or value of proved oil and gas reserves.

Changes in estimated reserve quantities

The net interest in estimated quantities of proved developed and undeveloped reserves of crude oil and natural gas at December 31, 2009, 2008 and 2007, and changes in such quantities during each of the years then ended were as follows (in thousands):

	2009			2008			2007		
	Oil Mbbl	Gas MMcf	MBOE	Oil Mbbl	Gas MMcf	MBOE	Oil Mbbl	Gas MMcf	MBOE
Proved developed and Undeveloped reserves:									
Beginning of year	125,251	724,135	245,940	116,602	315,464	169,179	112,538	226,363	150,262
Revision of previous estimates	2,786	(34,564)	(2,975)	(10,211)	(41,570)	(17,139)	(3,826)	3,358	(3,262)
Improved recovery	-	-	-	7,600	-	7,600	4,500	-	4,500
Extensions and discoveries	8,989	54,664	18,100	18,700	145,800	43,000	17,300	101,400	34,200
Property sales	-	(126,600)	(21,100)	-	-	-	(6,700)	-	(6,700)
Production	(7,186)	(22,657)	(10,962)	(7,440)	(25,559)	(11,700)	(7,210)	(15,657)	(9,819)
Purchase of reserves in place	100	37,200	6,300	-	330,000	55,000	-	-	-
End of year	129,940	632,178	235,303	125,251	724,135	245,940	116,602	315,464	169,179
Proved developed reserves:									
Beginning of year	74,616	361,575	134,879	78,339	147,346	102,897	84,782	104,934	102,270
End of year	82,870	255,520	125,456	74,616	361,575	134,879	78,339	147,346	102,897

The standardized measure has been prepared using the average price during the 12 month period, determined as an unweighted average of the first-day-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions, and year-end costs, assuming statutory tax rates (adjusted for tax credits and other items), and a ten percent annual discount rate**.** No deduction has been made for depletion, depreciation or any indirect costs such as general corporate overhead or interest expense. Cash outflows for future production and development costs include those cash flows associated with the ultimate settlement of the asset retirement obligation.

Excluding the effect of production and property sales, reserves increased 21.5 million BOE from 2008 to 2009. The reserves increased 18 million BOE from the Company's drilling and completion activities and 6 million BOE from acquisitions. The acquisition reserves include the 6 million BOE purchase in the Piceance Basin. The 18 million BOE increase resulting from the Company's drilling and completion activities were primarily at its Diatomite fields in California and its fields in the Piceance Basin. Reserve revisions across the company resulted in a decrease of 3 million BOE due to performance. Specifically, the decrease is attributable to a 1 million BOE increase in California, a 5 million BOE increase in the Rockies, offset by a 9 million BOE decrease in East Texas.

The reserve sales of 21 million BOE resulted from the sale of the Company's DJ basin reserves.

Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves (in thousands):

	2009	2008	2007
Future cash inflows	$ 9,028,991	$ 7,384,692	$ 11,211,151
Future production costs	(3,826,832)	(2,920,664)	(3,275,397)
Future development costs	(1,159,465)	(1,196,394)	(812,070)
Future income tax expense	(969,771)	(511,291)	(2,286,296)
Future net cash flows	3,072,923	2,756,343	4,837,388
10% annual discount for estimated timing of cash flows	(1,627,176)	(1,620,762)	(2,417,882)
Standardized measure of discounted future net cash flows	$ 1,445,747	$ 1,135,581	$ 2,419,506
Average sales prices at December 31 (a):			
Oil ($/Bbl)	$ 52.06	$ 30.03	$ 79.19
Gas ($/Mcf)	$ 3.58	$ 4.85	$ 6.27
BOE Price	$ 38.37	$ 30.92	$ 66.27

(a) The new SEC and FASB reserves reporting rules require the use of 12-month average commodity prices effective for 2009, instead of year-end commodity prices used in 2008 and 2007.

Changes in standardized measure of discounted future net cash flows from proved oil and gas reserves (in thousands):

	2009	2008	2007
Standardized measure - beginning of year	$ 1,135,581	$ 2,419,506	$ 1,182,268
Sales of oil and gas produced, net of production costs	(353,052)	(497,866)	(326,174)
Revisions to estimates of proved reserves:			
Net changes in sales prices and production costs	637,882	(2,686,941)	1,451,140
Revisions of previous quantity estimates	(33,943)	(144,466)	(78,758)
Improved recovery	-	64,058	108,655
Extensions and discoveries	206,542	362,435	825,775
Change in estimated future development costs	(52,824)	(352,061)	(286,439)
Purchases of reserves in place	29,348	667,862	-
Sales of reserves in place	(138,265)	-	(98,680)
Development costs incurred during the period	110,200	173,184	132,002
Accretion of discount	131,745	354,672	162,257
Income taxes	(190,727)	631,372	(687,103)
Other	(36,740)	143,826	34,563
Net increase (decrease)	310,166	(1,283,925)	1,237,238
Standardized measure - end of year	$ 1,445,747	$ 1,135,581	$ 2,419,506

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of December 31, 2009, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended (the Exchange Act).

Our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2009, our disclosure controls and procedures are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There was no change in our internal control over financial reporting that occurred during the period ended December 31, 2009 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management’s Report on Internal Control Over Financial Reporting

Internal control over financial reporting is defined in Rule 13a-15(f) and 15d-15(f) promulgated under the Securities Exchange Act of 1934, as amended, as a process designed by, or under the supervision of, our principal executive and principal financial officers, or persons performing similar functions, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with U.S. generally accepted accounting principles and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of our management and Directors; and
- provide reasonable assurance regarding prevention or the timely detection of unauthorized acquisition, or the use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control - Integrated Framework,* management concluded that our internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers and Corporate Governance

The information called for by Item 10 is incorporated by reference from information under the captions “Corporate Governance,” “Meetings and Committees of our Board” and “Compliance with Section 16(a) of the Securities Exchange Act of 1934” in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year. Information regarding Executive Officers is contained in this report in Item 1 Business of this Form 10-K.

Item 11. Executive Compensation

The information called for by Item 11 is incorporated by reference from information under the caption "Executive Compensation" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information called for by Item 12 is incorporated by reference from information under the captions "Security Ownership" and "Principal Shareholders" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year and Item 5 Market for the Registrant's Common Equity and Related Shareholder Matters and Issuer Purchases of Equity Securities of this Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information called for by Item 13 is incorporated by reference from information under the caption "Certain Relationships and Related Transactions" in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

Item 14. Principal Accounting Fees and Services

The information called for by Item 14 is incorporated by reference from the information under the caption “Fees to Independent Registered Public Accounting Firms for 2009 and 2008” in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

PART IV

Item 15. Exhibits, Financial Statement Schedules

A. Financial Statements and Schedules

See Item 8 Index to Financial Statements and Supplementary Data in this Form 10-K.

B. Exhibits

Exhibit No.	Description of Exhibit
3.1*	Registrant's Amended and Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Registrant’s Quarterly Report on Form 10-Q for the period ended June 30, 2006, File No. 1-09735).
3.2*	Registrant's Restated Bylaws dated December 11, 2009 (filed as Exhibit 3.1 to the Registrant's Current Report on Form 8-K on December 11, 2009, File No. 1-09735).
4.1*	Form of Indenture between Berry Petroleum Company and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.3 to the Registrant’s Registration Statement on Form S-3ASR on June 15, 2006, File No. 1-9735).
4.2*	First Supplemental Indenture, dated as of October 24, 2006, between the Registrant and Wells Fargo Bank, National Association as Trustee relating to the Registrant's 8 1/4% Senior Subordinated Notes due 2016 (filed as Exhibit 4.1 to the Registrant's Current Report on Form 8-K on October 25, 2006 File No. 1-9735).
4.3*	Registrant’s 8.25% Senior Subordinated Notes (filed as Form 425B5 on October 19, 2006).
4.4*	Registrant's Certificate of Designation, Preferences and Rights of Series B Junior Participating Preferred Stock (filed as Exhibit A to the Registrant's Registration Statement on Form 8-A12B on December 7, 1999, File No. 001-09735).
4.5*	Rights Agreement between Registrant and ChaseMellon Shareholder Services, L.L.C. dated as of December 8, 1999 (filed by the Registrant on Form 8-A12B on December 7, 1999, File No. 001-09735).
4.6*	Registrant’s 10¼ % Senior Notes due 2014 (filed as Form 425B5 on August 12, 2009)
4.7*	Indenture, dated June 15, 2006,between Berry Petroleum Company and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.1 to the Registrant’s Current Report on Form 8-K on May 29, 2009, File No. 1-09735)
4.8*	First Supplemental Indenture, dated May 27, 2009, between Berry Petroleum Company and Wells Fargo Bank, National Association, as Trustee (filed as Exhibit 4.2 to the Registrant’s Current Report on Form 8-K on May 29, 2009, File No. 1-09735)
4.9*	Form of 10 ¼% Senior Notes due 2014 (Included in Exhibit 4.2 to the Registrant’s Current Report on Form 8-K on May 29, 2009, File No. 1-09735)
10.1*	Instrument for Settlement of Claims and Mutual Release by and among Registrant, Victory Oil Company, the Crail Fund and Victory Holding Company effective October 31, 1986 (filed as Exhibit 10.13 to Amendment No. 1 to the Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240).
10.2*	Description of Short-Term Cash Incentive Plan of Registrant (filed as Exhibit 10.1 to the Registrant’s Annual Report on Form 10-K for the period ended December 31, 2006, File No. 1-9735).
10.3*	Form of Change in Control Severance Protection Agreement dated August 24, 2006, by and between Registrant and selected employees of the Company (filed as Exhibit 99.1 to the Registrant’s Current Report on Form 8-K on August 24, 2006, File No. 1-9735).
10.4*	Amended and Restated 1994 Stock Option Plan (filed as Exhibit 4.1 to the Registrant’s Registration Statement on Form S-8 filed on August 20, 2002, File No. 333-98379).
10.5*	First Amendment to the Registrant’s Amended and Restated 1994 Stock Option Plan dated as of June 23, 2006 (filed as Exhibit 99.3 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.6*	Berry Petroleum Company 2005 Equity Incentive Plan (filed as Exhibit 4.2 to the Registrant’s Form S-8 filed on July 29, 2005, File No. 333-127018).
10.7*	Form of the Stock Option Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 4.3 to the Registrant’s Form S-8 filed on July 29, 2005, File No. 333-127018).
10.8*	Form of the Stock Appreciation Rights Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 4.4 to the Registrant’s Form S-8 filed on July 29, 2005, File No. 333-127018).
10.9*	Form of Stock Award Agreement, by and between Registrant and selected employees, directors, and consultants (filed as Exhibit 99.4 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.10*	Form of Restricted Stock Award Agreement, by and between Registrant and selected directors (filed as Exhibit 99.1 on Form 8-K filed on December 17, 2007, File No. 1-9735).
10.11*	Form of Restricted Stock Award Agreement, by and between Registrant and selected officers (filed as Exhibit 99.2on Form 8-K December 17, 2007, File No. 1-9735).

10.12	Non-Employee Director Deferred Stock and Compensation Plan (as amended and restated effective November 19, 2008).
10.13*	Amended and Restated Employment Contract dated as of June 23, 2006 by and between the Registrant and Robert F. Heinemann (filed as Exhibit 99.1 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.14*	Stock Award Agreement dated as of June 23, 2006 by and between the Registrant and Robert F. Heinemann (filed as Exhibit 99.2 to the Registrant's Current Report on Form 8-K June 26, 2006, File No. 1-9735).
10.15*	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and David D. Wolf (Filed as Exhibit 10.1 in Registrant’s Form 8-K/A filed on November 21, 2008, File No. 1-9735)
10.16*	Employment Agreement dated November 19, 2008 by and between Berry Petroleum Company and Michael Duginski (filed as Exhibit 10.1 in Registrant’s Form 8-K filed on November 21, 2008, File No. 1-9735)
10.17*	Amended and Restated Credit Agreement, dated as of July 15, 2008, by and between the Registrant and Wells Fargo Bank, N.A. and other financial institutions (filed as Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2008, File No. 1-9735).
10.18*	Credit Agreement by and among Berry Petroleum Company, Societe Generale, SG Americas Securities, LLC, BNP Paribas Securities Corp., BNP Paribas, and other financial institutions dated July 31, 2008 (filed as Exhibit 10.2 on Form 10-Q for the period ended September 30, 2008, File No. 1-09735).
10.19*	First Amendment to Amended and Restated Credit Agreement, by and between Berry Petroleum Company, Wells Fargo Bank, N.A. and other financial institutions, dated as of October 17, 2008 (filed on October 17, 2008, as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K File No. 1-9735).
10.20*	Joinder Agreement dated November 13, 2008 by and among Berry Petroleum Company, Wells Fargo Bank, N.A., and Bank of Montreal (filed as Exhibit 10.1in Registrant’s Form 8-K filed on November 17, 2008, File No. 1-9735).
10.22*	Crude oil purchase contract, dated November 14, 2005 between Registrant and Big West of California, LLC (filed as Exhibit 99.2 on Form 8-K filed on November 22, 2005, File No. 1-9735).
10.21*	Joinder Agreement dated December 2, 2008 by and among Berry Petroleum Company, Wells Fargo Bank, N.A., and Calyon New York Branch (filed as Exhibit 10.1in Registrant’s Form 8-K filed on December 4, 2008, File No. 1-9735).
10.23* **	Carry and Earning Agreement, dated June 7, 2006, between Registrant and EnCana Oil & Gas (USA), Inc. (filed as Exhibit 99.2 on Form 8-K on June 19, 2006, File No. 1-9735).
10.24* **	Crude Oil Supply Agreement between the Registrant and Holly Refining and Marketing Company - Woods Cross (filed as Exhibit 10.22 to the Registrant’s Annual Report on Form 10-K for the period ended December 31,2006, File No. 1-0735).
10.25*	Purchase and Sale Agreement Between O’Brien Resources, LLC, Sepco II, LLC, Liberty Energy, LLC, Crow Horizons Company and O’Benco II LP collectively as Seller and Berry Petroleum Company as Purchaser, dated as of June 10, 2008 (filed as Exhibit 10.2 to the Registrant’s Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 1-9735).
10.26*	Overriding Royalty Purchase Agreement between O’Brien Resources, LLC, as Seller and Berry Petroleum Company as Purchaser, dated as of June 10, 2008 (filed as Exhibit 10.3 to the Registrant’s Quarterly Report on Form 10-Q for the period ended June 30, 2008, File No. 1-9735).
10.27*	Second Amendment to the Amended and Restated Credit Agreement, dated as of February 19, 2009 (filed as Exhibit 10.1 to the Registrant’s Current Report on Form 8-K on February 20, 2009, File No. 1-9735).
10.28 * **	Crude Oil Purchase Contract dated March 20, 2009, between the Registrant and Tesoro Corporation (filed as Exhibit 10.1 to the Registrant’s Quarterly Report on Form 10-Q for the period ended March 31, 2009, File No. 1-09735)
10.29*	Third Amendment to Amended and Restated Credit Agreement dated April 27, 2009 by and among Registrant, Wells Fargo Bank National Association, individually and as administrative agent, and certain financial institutions, as lenders (filed as Exhibit 10.2 to the Registrant’s Quarterly Report on Form 10- for the period ended March 31, 2009, File No. 1-09735)
10.30*	Second Lien Credit Agreement date April 27, 2009, among Registrant, Wells Fargo Energy Capital, Inc., as administrative agent, and certain financial institutions, as Lenders and agents (Filed as Exhibit 10.3 to the Registrant’s Quarterly Report on Form 10- for the period ended March 31, 2009, File No. 1-09735)
10.31*	Underwriting Agreement, dated May 21, 2009, by and between Registrant and Wachovia Capital Markets, LLC, RBS Securities Inc., BNP Paribas Securities Corp., SG Americas Securities, LLC and Calyon Securities (USA) Inc., (filed as Exhibit 1.1 to the Registrant’s Current Report on Form 8-K on May 27, 2009, File No. 1-9735).
10.32*	Underwriting Agreement, dated August 11, 2009, by and among Registrant and Wachovia Capital Markets, LLC, RBS Securities Inc., BNP Paribas Securities Corp., SG Americas Securities, LLC and Calyon Securities (USA) Inc., as representatives of the underwriters named therein (filed as Exhibit 1.1 to the Registrant’s Current Report on Form 8-K on August 13, 2009, File No. 1-9735).

10.33* **	Crude Oil Purchase Contract dated September 24, 2009 between the Registrant and ExxonMobil Oil Corporation (filed as Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q for the period ended September 30, 2009, File No. 1-9735).
10.34*	Underwriting Agreement dated January 14, 2010 by and between Registrant and the several Underwriters listed in Schedule 1 thereto (filed as Exhibit 1.1 to the Registrant's Current Report on Form 8-K on January 19, 2010, File No. 1-9735).
12.1	Ratio of Earnings to Fixed Charges.
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.
23.2	Consent of DeGolyer and MacNaughton.
31.1	Certification of Chief Executive Officer pursuant to SEC Rule 13(a)-14(a).
31.2	Certification of Chief Financial Officer pursuant to SEC Rule 13(a)-14(a).
32.1	Certification of Chief Executive Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code.
32.2	Certification of Chief Financial Officer pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code.
99.1*	Form of Indemnity Agreement of Registrant (filed as Exhibit 99.1 in Registrant's Annual Report on Form 10-K filed on March 31, 2005, File No. 1-9735).
99.2*	Form of "B" Group Trust (filed as Exhibit 28.3 to Amendment No. 1 to Registrant's Registration Statement on Form S-4 filed on May 22, 1987, File No. 33-13240).
99.3	Report of DeGolyer and MacNaughton dated February 19, 2010 regarding Registrant's reserves estimates.

* Incorporated by reference

** Portions of this exhibit have been omitted pursuant to a request for confidential treatment

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 25, 2010.

BERRY PETROLEUM COMPANY

/s/ Robert F. Heinemann ROBERT F. HEINEMANN President, Chief Executive Officer and Director	/s/ David D. Wolf DAVID D. WOLF Executive Vice President and Chief Financial Officer (Principal Financial Officer)	/s/ Shawn M. Canaday SHAWN M. CANADAY Vice President of Finance (Principal Accounting Officer)

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

Name	Office	Date
/s/ Martin H. Young, Jr. Martin H. Young, Jr.	Chairman of the Board, Director	February 25, 2010
/s/ Robert F. Heinemann Robert F. Heinemann	President, Chief Executive Officer and Director	February 25, 2010
/s/ Joseph H. Bryant Joseph H. Bryant	Director	February 25, 2010
/s/ Ralph B. Busch, III Ralph B. Busch, III	Director	February 25, 2010
/s/ William E. Bush, Jr. William E. Bush, Jr.	Director	February 25, 2010
/s/ Stephen L. Cropper Stephen L. Cropper	Director	February 25, 2010
/s/ J. Herbert Gaul, Jr. J. Herbert Gaul, Jr.	Director	February 25, 2010
/s/ Thomas J. Jamieson Thomas J. Jamieson	Director	February 25, 2010
/s/ J. Frank Keller J. Frank Keller	Director	February 25, 2010

Exhibit 10.12

BERRY PETROLEUM COMPANY

NON-EMPLOYEE DIRECTOR

DEFERRED STOCK AND COMPENSATION PLAN

(as amended and restated effective November 19, 2008)

Section 1. Establishment of Plan; Purpose. The Berry Petroleum Company Non-Employee Director Deferred Stock and Compensation Plan (the "Plan") is hereby established to permit Eligible Directors, in recognition of their contributions to the Company (a) to receive Shares in lieu of Compensation and (b) to defer recognition of their Compensation in the manner described below. The Plan is intended to enable the Company to attract, retain and motivate qualified directors and to enhance the long-term mutuality of interest between Directors and stockholders of the Company.

Section 2. Definitions. When used in this Plan, the following terms shall have the definitions set forth in this Section:

2.1. "Accounts" shall mean an Eligible Director's Stock Unit Account and Interest Account.

2.2. "Board of Directors" shall mean the Board of Directors of the Company.

2.3. "Committee" shall mean the Compensation Committee of the Board of Directors or such other committee of the Board as the Board shall designate from time to time.

2.4. "Company" shall mean Berry Petroleum Company, a Delaware corporation.

2.5. "Compensation" shall mean (a) the quarterly fee earned by an Eligible Director for service as a Director; (b) the fee, if any, earned by an Eligible Director for service as a member of a committee of the Board of Directors; (c) the fee earned by an Eligible Director for (i) attendance at meetings of the Board of Directors and (ii) attendance at meetings of committees; and (d) any other cash compensation earned for service as a Director.

2.6. "Determination Date" shall mean, for the Compensation earned by an Eligible Director (x) for the services identified in subsections (a), (b) and (c) of the definition of "Compensation" above, the last trading day of the fiscal quarter in which such service was provided, and (y) pursuant to subsection (d) of the definition of Compensation above, the date designated by the Board of Directors for the payment of such Compensation, or if such date is not a trading day, the first trading day thereafter.

2.7. "Director" shall mean any member of the Board of Directors, whether or not such member is an Eligible Director.

2.8. "Effective Date" shall mean the date on which the Plan is approved by the stockholders of the Company.

2.9. "Eligible Director" shall mean a member of the Board of Directors who is not an employee of the Company.

2.10. "Exchange Act" shall mean the Securities Exchange Act of 1934, as amended.

2.11. "Fair Market Value" shall mean the closing price or the last sale (as reported by the New York Stock Exchange) of a Share or any other reasonable basis using actual transactions of such Shares as reported and as shall be consistently applied by the Committee.

2.12. "Interest Account" shall mean the bookkeeping account established to record the interests of an Eligible Director with respect to deferred Compensation that is not allocated to Units in a Stock Unit Account.

2.13. "Shares" shall mean shares of Stock.

2.14. "Stock" shall mean the Class A Common Stock of the Company.

2.15. "Stock Unit Account" shall mean a bookkeeping account established to record the interests of an Eligible Director who has elected to have deferred Compensation credited as Units in this Account.

2.16. "Unit" shall mean a contractual obligation of the Company to deliver a Share to an Eligible Director or the beneficiary or estate of such Eligible Director as provided herein.

Section 3. **Administration**. The Plan shall be administered by the Committee.

Section 4. **Deferred Compensation Program.**

4.1. **Election to Defer**. On or before December 31 of any calendar year, an Eligible Director may elect to defer receipt of all or any part of any Compensation payable in respect of the calendar year following the year in which such election is made, and to have such amounts credited, in whole or in part, to a Stock Unit Account or an Interest Account. Any person who shall become an Eligible Director during any calendar year may elect, not later than the 30th day after his term as a Director begins, to defer payment of all or any part of his Compensation payable for the portion of such calendar year following such election.

4.2. **Method of Election**. A deferral election shall be made by written notice filed with the Corporate Secretary of the Company. Such election shall continue in effect (including with respect to Compensation payable for subsequent calendar years) unless and until the Eligible Director revokes or modifies such election by written notice filed with the Corporate Secretary. Any such revocation or modification of a deferral election shall become effective as of December 31 of the year in which such notice is given and only with respect to Compensation payable in respect of the calendar year following the year in which such revocation or modification is made. Amounts credited to the Eligible Director's Stock Unit Account prior to the effective date of any such revocation or modification of a deferral election shall not be affected by such revocation or modification and shall be credited and distributed only in accordance with the deferral election in place prior to such revocation and modification and otherwise in accordance with the applicable terms of the Plan. An Eligible Director who has revoked an election to participate in the Plan may file a new election to defer Compensation with respect to services rendered in the calendar year following the year in which such new election is filed with the Corporate Secretary of the Company.

4.3. Investment Election. At the time an Eligible Director elects to defer receipt of Compensation pursuant to Section 4.1, the Eligible Director shall also designate in writing the portion of such Compensation, stated as a whole percentage, to be credited to the Interest Account and the portion to be credited to the Stock Unit Account. If an Eligible Director fails to designate the allocation between the two Accounts, 100% of such Compensation shall be credited to the Interest Account. By written notice to the Corporate Secretary, an Eligible Director may change the investment election and the manner in which Compensation is allocated among the Accounts but only with respect to services to be rendered in the calendar year following the year in which such new investment election is filed with the Corporate Secretary.

4.4. Interest Account.

a. Any Compensation allocated to an Eligible Director's Interest Account shall be deemed earned and credited to the Interest Account as of the Determination Date.

b. Any amounts credited to the Interest Account shall be credited with interest at the annual rate for the 3-month treasury bill as of the Determination Date as quoted in the Wall Street Journal, times 3/12.

4.5. Stock Unit Account.

a. Any Compensation allocated to an Eligible Director's Stock Unit Account shall be deemed earned and credited to Units in the Stock Unit Account as of the Determination Date.

b. The number of Units allocated to the Eligible Director's Stock Unit Account pursuant to subsection (a) above shall be equal to the quotient of (i) the aggregate Compensation allocated to the Stock Unit Account as of the Determination Date divided by (ii) the Fair Market Value on the Determination Date. Fractional Units shall be credited, but shall be rounded to the nearest hundredth percentile, with amounts equal to or greater than .005 rounded up and amounts less than .005 rounded down.

4.6. Dividend Equivalents.

a. An Eligible Director who has elected to defer Compensation to a Stock Unit Account shall have no rights as a stockholder of the Company with respect to any Units until Shares are distributed and delivered to the Eligible Director.

b. Notwithstanding the provisions of subsection (a), each Eligible Director who has allocated Compensation to a Stock Unit Account shall have the right to receive an amount equal to the dividend per Share declared by the Company on the applicable dividend payment date (which, in the case of any dividend distributable in property other than Shares, shall be the per Share value of such dividend, as determined by the Company for purposes of income tax reporting) times the number of Units held by such Eligible Director in his Stock Unit Account (a "Dividend Equivalent").

c. Dividend Equivalents shall be treated as reinvested in an additional number of Units and credited to the Eligible Director's Stock Unit Account.

d. The additional number of Units to be credited to the Eligible Director's Stock Unit Account pursuant to (c) (iii) shall be determined by dividing (i) the product of (A) the number of Units in the Eligible Director's Stock Unit Account on the date the dividend is declared, and (B) the amount of any cash dividend declared by the Company on a Share (or, in the case of any dividend distributable in property other than Shares, the per share value of such dividend, as determined by the Company for purposes of income tax reporting), by (ii) the Fair Market Value on the last trading day of the fiscal quarter in which the dividend is declared.

e. Notwithstanding the date used for purposes of determining the number of additional Units as provided in subsection (d) above, the additional Units to be credited for Dividend Equivalents shall be deemed earned and credited to the Eligible Director's Stock Unit Account on the last trading day of the fiscal quarter in which such dividend is declared.

f. In the event of any stock split, stock dividend, recapitalization, reorganization or other corporate transaction affecting the capital structure of the Company, the Committee shall make such adjustments to the number of Units credited to each Eligible Director's Stock Unit Account as the Committee shall deem necessary or appropriate to prevent the dilution or enlargement of such Eligible Director's rights and such adjustment shall be made and effective as of the last day of the fiscal quarter in which such corporate transaction has occurred.

4.7. Distribution Election.

a. At the time an Eligible Director makes a deferral election pursuant to Section 4.1, the Eligible Director shall also file with the Corporate Secretary a written election (a "Distribution Election").

b. The distribution from the Stock Unit Account shall be made in Shares and the distribution from the Interest Account shall be made in cash. The Distribution Election shall specify that such distribution shall commence, at the election of the Eligible Director, as soon as practicable following the first business day of the calendar month following the date the Eligible Director ceases to be a Director or on the first business day following the calendar year in which the Eligible Director ceases to be a Director.

c. Such distribution shall be in one lump sum payment or in such number of annual installments (not to exceed ten (10)) as the Eligible Director may designate on the Distribution Election. The amount of any installment payment shall be determined by multiplying the amount credited to the Accounts of an Eligible Director immediately prior to the distribution by a fraction, the numerator of which is one and the denominator of which is the number of installments (including the current installment) remaining to be paid.

d. An Eligible Director may at any time prior to the time at which the Eligible Director ceases to be a Director, and from time to time, change any Distribution Election applicable to his Accounts, provided that no election to change the timing or form of any final distribution shall be effective unless (i) it is made in writing and received by the Corporate Secretary at least one (1) year prior to the time at which the Eligible Director ceases to be a director and (ii) the start date of any installment distribution or lump sum payment is delayed at least five years.

4.8. Unforeseeable Emergency Withdrawal. Any Eligible Director may, after submission of a written request to the Corporate Secretary and such written evidence of the Eligible Director's financial condition as the Committee may reasonably request, withdraw from his Interest Account (but not from his Stock Unit Account) up to such amount as the Committee shall determine to be necessary to alleviate the Eligible Director's unforeseeable emergency plus applicable taxes as a result of the distribution. Withdrawals will only be approved for a severe financial hardship to the Eligible Director resulting from an illness or accident of the Eligible Director, his or her spouse or dependent (as defined in IRC § 409A (a) (2) (B) (ii)).

4.9. Timing and Form of Distributions.

a. Any distribution to be made hereunder, whether in the form of a lump sum payment or installments, following the termination of an Eligible Director's service as a Director shall commence in accordance with the Distribution Election made by the Eligible Director pursuant to Section 4.7.

b. If an Eligible Director fails to specify in accordance with Section 4.7 a commencement date for a distribution or whether such distribution shall be made in a lump sum payment or a number of installments, such distribution shall be made in a lump sum payment and commence on the first business day of the month immediately following the date on which the Eligible Director ceases to be a Director. In the case of any distribution being made in annual installments, each installment after the first installment shall be paid on the first business day of each subsequent calendar year, or as soon as practical thereafter, until the entire amount subject to such Distribution Election shall have been paid.

Section 5. Unfunded Status. The Company shall be under no obligation to establish a fund or reserve in order to pay the benefits under the Plan. A Unit represents a contractual obligation of the Company to deliver Shares to an Eligible Director as provided herein. The Company has not segregated or earmarked any Shares or any of the Company's assets for the benefit of an Eligible Director or his beneficiary or estate, and the Plan does not, and shall not be construed to, require the Company to do so. The Eligible Director and his beneficiary or estate shall have only an unsecured, contractual right against the Company with respect to any Units granted or amounts credited to an Eligible Director's Accounts hereunder, and such right shall not be deemed superior to the right of any other creditor. Units shall not be deemed to constitute options or rights to purchase Stock.

Section 6. Amendment and Termination. The Plan may be amended at any time by the Committee or the Board of Directors. Unless the Board otherwise specifies at the time of such termination, the termination of the Plan will not result in the premature distribution of the amounts credited to an Eligible Director's Accounts.

Section 7. General Provisions.

7.1. No Right to Serve as a Director. This Plan shall not impose any obligations on the Company to retain any Eligible Director as a Director nor shall it impose any obligation on the part of any Eligible Director to remain as a Director of the Company.

7.2. Rights of a Terminated Director. Notwithstanding the fact that an Eligible Director ceases to be a director during any fiscal quarter, the Eligible Director's Accounts shall be credited, on the last trading day of the fiscal quarter, with all Compensation and Dividend Equivalents earned as of the last business day he served as an Eligible Director.

7.3. Construction of the Plan. The validity, construction, interpretation, administration and effect of the Plan and the rights relating to the Plan, shall be determined solely in accordance with the laws of the State of Delaware.

7.4. No Right to Particular Assets. Nothing contained in this Plan and no action taken pursuant to this Plan shall create or be construed to create a trust of any kind or any fiduciary relationship between the Company and any Eligible Director, the executor, administrator or other personal representative or designated beneficiary of such Eligible Director, or any other persons. Any reserves that may be established by the Company in connection with Units granted under this Plan shall continue to be treated as the assets of the Company for federal income tax purposes and remain subject to the claims of the Company's creditors. To the extent that any Eligible Director or the executor, administrator, or other personal representative of such Eligible Director, acquires a right to receive any payment from the Company pursuant to this Plan, such right shall be no greater than the right of an unsecured general creditor of the Company.

7.5. Severability of Provisions. If any provision of this Plan shall be held invalid or unenforceable, such invalidity or unenforceability shall not affect any other provisions hereof, and this Plan shall be construed and enforced as if such provision had not been included.

7.6. Incapacity. Any benefit payable to or for the benefit of a minor, an incompetent person or other person incapable of receipting therefore shall be deemed paid when paid to such person's guardian or to the party providing or reasonably appearing to provide for the care of such person, and such payment shall fully discharge any liability or obligation of the Board of Directors, the Company and all other parties with respect thereto.

7.7. Headings and Captions. The headings and captions herein are provided for reference and convenience only, shall not be considered part of this Plan, and shall not be employed in the construction of this Plan.

Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(in thousands, except ratios)

	12/31/09	12/31/08	12/31/07	12/31/06	12/31/05	12/31/04
Pre-tax income from continuing operations	$ 88,317	$ 192,084	$ 206,344	$ 159,906	$ 150,289	$ 89,518
Interest expense	50,738	26,209	17,287	10,247	6,048	2,067
Capitalized interest	30,107	23,209	18,104	9,339	-	-
Earnings	$ 139,055	$ 218,293	$ 233,631	$ 170,153	$ 156,337	$ 91,585
Ratio of earnings to fixed charges	**1.7**	**4.4**	**6.3**	**8.7**	**25.8**	**44.3**

For purposes of this table, “earnings” consists of income before income taxes from continuing operations plus fixed charges and less capitalized interest. “Fixed charges” consists of interest expense and capitalized interest (for both continuing and discontinued operations).

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-135055, 333-157507, 333-161243, 333-163743) and Form S-8 (Nos. 333-62799, 333-62871, 333-62873, 333-98379 and 333-127018) of Berry Petroleum Company of our report dated February 25, 2010 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP

Denver, Colorado
February 25, 2010

Exhibit 23.2

February 23, 2010

Berry Petroleum Company
1999 Broadway Street, Suite 3700
Denver, CO 80202

Gentlemen:

We hereby consent to (i) the inclusion of our third party letter report dated February 19, 2010, containing our opinion on the proved reserves attributable to certain properties owned by Berry Petroleum Company, as of December 31, 2009, (ii) the use of and reference to our “Appraisal Report as of December 31, 2008 on Certain Properties owned by Berry Petroleum Company,” and our “Appraisal Report as of December 31, 2007 on Certain Properties owned by Berry Petroleum Company” (the Reports) under the captions “Properties” and “Reserves” in Item 1, “Selected Financial Data” in Item 6, and “Supplemental Information About Oil & Gas Producing Activities (Unaudited)” in Item 8 of the Annual Report on Form 10–K for the fiscal year ended December 31, 2009, of Berry Petroleum Company (the Annual Report); and (iii) the use of and reference to the name DeGolyer and MacNaughton as the independent petroleum engineering firm that prepared the Reports under such items; provided, however, that since the cash-flow calculations in the Annual Report include estimated income taxes not included in the Reports, we are unable to verify the accuracy of the cash-flow values in the Annual Report.

Very truly yours,

/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, certify that:

1. I have reviewed this report on Form 10-K of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, and its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions abut the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

/s/ Robert F. Heinemann
Robert F. Heinemann
President, Chief Executive Officer and Director

February 25, 2010

Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, David D. Wolf, certify that:

1. I have reviewed this report on Form 10-K of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

/s/ David D. Wolf
David D. Wolf
Executive Vice President and Chief Financial Officer

February 25, 2010

Exhibit 32.1

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Annual Report of Berry Petroleum Company (the "Company") on Form 10-K for the period ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

	/s/ Robert F. Heinemann
	Robert F. Heinemann
February 25, 2010	President, Chief Executive Officer and Director

Exhibit 32.2

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Annual Report of Berry Petroleum Company (the "Company") on Form 10-K for the period ending December 31, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David D. Wolf, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David D. Wolf
David D. Wolf
Executive Vice President and Chief Financial Officer

February 25, 2010

Exhibit 99.3

February 19, 2010

Berry Petroleum Company
1999 Broadway
Suite 3700
Denver, Colorado 80202

Gentlemen:

Pursuant to your request, we have prepared estimates of the extent and value of the net proved crude oil, condensate, natural gas liquids (NGL), and natural gas reserves, as of December 31, 2009, of certain properties owned by Berry Petroleum Company (Berry). The properties appraised, consisting of fee, leasehold, and royalty interests, are located in California, Colorado, Louisiana, Nevada, Oklahoma, Texas, Utah, and Wyoming, Berry has represented that these properties account for 100 percent of Berry's net proved reserves as of December 31, 2009.

Estimates of proved reserves presented in this report have been prepared in compliance with the regulations promulgated by the United States Securities and Exchange Commission (SEC). These reserves definitions are discussed in detail under the Definition of Reserves heading of this letter.

Reserves included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum to be produced from these properties after December 31, 2009. Net reserves are defined as that portion of the gross reserves attributable to the interests owned by Berry after deducting all interests owned by others. Gas volumes shown herein are sales-gas volumes and are expressed at a temperature base of 60 degrees Fahrenheit and at the legal pressure base of the state in which the interest is located. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Condensate reserves estimated herein are those to be recovered by normal field separation. NGL reserves are those attributed to the leasehold interests according to processing agreements.

Values of proved reserves shown herein are expressed in terms of estimated future gross revenue, future net revenue, and present worth. Future gross revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting estimated severance taxes, ad valorem taxes, operating expenses, and capital costs from the future gross revenue. Operating expenses include field operating expenses, transportation expenses, compression charges, and an allocation of overhead that directly relates to production activities. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization.

Estimates of oil, condensate, NGL, and natural gas should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserves estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Data used in this report were obtained from reviews with Berry personnel, Berry files, from records on file with the appropriate regulatory agencies, and from public sources. Additionally, this information includes data supplied by Petroleum Information/Dwights LLC; Copyright 2009 Petroleum Information/Dwights LLC. In the preparation of this report we have relied, without independent verification, upon such information furnished by Berry 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 that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

Methodology and Procedures

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate the original oil in place (OOIP) and the original gas in place (OGIP). Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure, and gas-oil ratio behavior, was used in the estimation of reserves.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Primary Economic Assumptions

The following economic assumptions were used for estimating existing and future prices and costs:

Oil, Condensate, NGL and Natural Gas Prices

Oil, condensate, NGL and natural gas prices were provided by Berry and are based on a 12-month average price (NYMEX price), calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Berry supplied differentials by certain geographic producing areas to a NYMEX Light Crude oil price of $61.18 per barrel and a NYMEX Contract Settlement gas price of $3.99 per million British thermal units. The prices were held constant thereafter and were not escalated for inflation.

Operating Expenses and Capital Costs

Current operating expenses and capital costs, based on information provided by Berry were used in estimating future expenses and costs required to operate the properties. In certain cases, future expenses, either higher or lower than current expenses, may have been used because of anticipated changes in operating conditions. Initial operating expenses were held constant for the lives of the properties and not escalated for inflation. Future capital costs were estimated using 2009 values and were not escalated for inflation.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its oil and gas reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2009, estimated oil and gas volumes. The reserves estimated in this report can be produced under current regulatory guidelines.

Summary of Oil and Gas Reserves and Revenue

The estimates of net proved reserves attributable to the properties appraised, as of December 31, 2009, are summarized by geographic area as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Oil and Condensate (Mbbl)	Natural Gas Liquids (Mbbl)	Sales Gas (MMcf)	Oil Equivalent (Mboe)
Proved Developed				
California	75,912	0	0	75,912
Colorado	203	0	73,625	12,474
Utah	4,339	821	27,871	9,805
Texas	0	1,587	154,019	27,257
Wyoming	0	0	3	1
Various (LA, NV,OK)	8	0	2	8
Total Proved Developed	80,462	2,408	255,520	125,457
Proved Undeveloped				
California	35,885	0	0	35,885
Colorado	711	0	284,159	48,071
Utah	8,491	1,115	21,158	13,133
Texas	0	868	71,341	12,758
Wyoming	0	0	0	0
Various (LA, NV,OK)	0	0	0	0
Total Proved Undeveloped	45,087	1,983	376,658	109,847
Total Proved	125,549	4,391	632,178	235,303

Note: Gas is converted to oil equivalent using a factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent

The estimated revenue and expenditures attributable to Berry's interests in the proved reserves, as of December 31, 2009, of the properties appraised under the aforementioned assumptions concerning future prices and costs are summarized as follows:

	Proved			
	Developed Producing (M$)	**Developed Nonproducing (M$)**	**Undeveloped (M$)**	**Total Proved (M$)**
Future Gross Revenue	3,990,871	1,262,923	3,775,197	9,028,991
Production and Ad Valorem Taxes	145,981	49,893	173,638	369,513
Operating Expenses	1,617,581	472,736	1,367,002	3,457,319
Capital Costs	148,920	98,191	912,354	1,159,465
Future Net Revenue*	2,078,389	642,102	1,322,203	4,042,694
Present Worth at 10 Percent*	1,159,841	262,718	426,611	1,849,170

* Future income taxes have not been taken into account in the preparation of these estimates.
Note: Numbers in tables may not add due to rounding.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the Financial Accounting Standards Board and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the Securities and Exchange Commission; provided, however, future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over 70 years. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Berry. Our fees were not contingent on the results of our evaluation. This letter report has been prepared at the request of Berry and should not be used for purposes other than those for which it is intended. DeGolyer and MacNaughton has used all procedures and methods that it considers necessary to prepare this report.

Submitted,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716