BERRY PETROLEUM CO
Form 10-K
February 28, 2012
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K
S Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2011
Commission file number 1-9735
BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

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

1999 Broadway
Suite 3700
Denver, Colorado 80202
(Address of principal executive offices, including zip code)
Registrant's telephone number, including area code:
(303) 999-4400
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Class A Common Stock, $0.01 par value (including associated stock purchase rights)	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ý NO o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES o NO ý
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ý NO o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES ý NO o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO ý
As of June 30, 2011, the aggregate market value of the voting and non-voting common stock held by non-affiliates was $2,583,421,226.
As of February 14, 2012, the registrant had 52,150,685 shares of Class A Common Stock outstanding. The registrant also had 1,797,784 shares of Class B Stock outstanding on February 14, 2012, all of which are held by an affiliate of the registrant.
DOCUMENTS INCORPORATED BY REFERENCE

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

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Forward Looking Statements

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

PART I

Item 1. Business

General

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

We operate in one industry segment, which is the production, development, exploitation and acquisition of oil and natural gas, and all of our operations are conducted in the United States. Consequently, we currently report a single industry segment. See Item 8. Financial Statements and Supplementary Data for financial information about this industry segment. Information contained in this Annual Report on Form 10-K reflects our business during the year ended December 31, 2011, unless noted otherwise.

Business Strategy

Our business strategy is to increase shareholder value by efficiently increasing production, reserves and cash flow, both through the drill bit and through acquisitions. We believe our inventory of drilling locations is ideally suited to growing production, reserves and cash flow due to predictable geology. Our strategy is based on the following:

- Pursuing the development of projects that we believe will generate attractive rates of return;
- Maintaining a balanced portfolio of long-lived oil and natural gas properties that provide stable cash flows;
- Maximizing production from our base oil assets;
- Selectively acquiring properties with an emphasis on oil; and
- Maintaining a strong financial position by investing our capital in a disciplined manner.

Business Strengths

We believe that the following strengths allow us to successfully execute our business strategy:

Low-Risk Multi-Year Drilling Inventory in Established Crude Oil Plays. We have a significant number of drilling locations in established crude oil plays that possess low geologic risk, leading to relatively predictable drilling results.

Our complementary mix of primary development locations as well as heavy oil thermal projects provide high operating margins and the financial flexibility to respond to commodity price environments and localized operating environments.

Balanced High Quality Asset Portfolio. Since 2002, we have grown our asset base and diversified our portfolio through acquisitions in the Permian and Uinta. Our portfolio provides us with the flexibility to allocate capital among a diverse set of high return oil assets.

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 as of December 31, 2011.

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Operational Control and Financial Flexibility. We exercise operating control over approximately 92% 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 and development budget primarily through our internally generated operating cash flows.

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

Acquisition and Divestiture Activities

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

2011 Acquisitions. In 2011, we made multiple acquisitions, each of which involved interests in properties located primarily in the Permian, for an aggregate of approximately $158.1 million.

2010 Acquisitions. In 2010, we made multiple acquisitions, each of which involved interests in properties located primarily in the Permian, for an aggregate of approximately $334.4 million.

2009 Divestitures. In 2009, we sold all of our interest in our assets in the Denver-Julesburg basin in Colorado (DJ) for approximately $139.8 million.

Properties

The following table provides information regarding our operations by area as of December 31, 2011:

Name, State	Total Net Acres		Proved Reserves (MMBOE)(1)	Proved Developed Reserves (MMBOE)(1)	Proved Undeveloped Reserves (MMBOE)(1)	2011 Gross Wells(2)		2011 Net Wells(2)
S. Midway, CA	3,913		58.0	50.9	7.1	40		40
N. Midway, CA	2,657		62.4	34.0	28.4	208		208
Permian, TX	41,793		56.9	16.5	40.4	97	(4)	69
Uinta, UT	99,723	(3)	23.2	13.3	9.9	54		45
Piceance, CO	8,077		55.0	11.9	43.1	5		5
E. Texas	4,671		19.4	18.2	1.2	—		—
Totals	160,834		274.9	144.8	130.1	404		367

(1) MMBOE—Million BOEs.
(2) Represents gross and net productive wells drilled during 2011.
(3) Excludes 45,000 net acres subject to drill-to-earn agreements. Includes 4,768 net acres in Nevada.
(4) Includes 25 wells in which we have an average interest of approximately 0.7% each, or approximately 0.2 total net wells.

We currently have six asset teams as follows: South Midway-Sunset (SMWSS) – Steam Floods, North Midway-Sunset (NMWSS) – Diatomite, Permian, Uinta, Piceance and E. Texas.

SMWSS – Steam Floods. Our SMWSS – Steam Floods assets include our Homebase, Formax, Ethel D, Placerita, and Poso Creek properties. Production from our Homebase, Formax and Ethel D properties in the South Midway-Sunset Field relies on thermal enhanced oil recovery (EOR) methods, primarily cyclic steaming, to place steam effectively into the remaining oil column. These are some of our most thermally mature assets, with production from our Ethel D properties dating back to 1909. In 2011, we expanded our steam flood at our Homebase and Formax properties, drilling five horizontal wells, three vertical wells and six steam injection wells. At our Ethel D property, we expanded development of a new steam flood, drilling 17 producing wells and three steam injection wells. In 2012, we plan to continue development of the steam flood at our Ethel D property, adding additional steam generation capacity and drilling approximately 40 producing wells and five steam injection wells. In addition, we plan to drill eight horizontal wells and two vertical wells on our Homebase and Formax properties.

In 2003, we acquired our Poso Creek properties in the San Joaquin Valley and have proceeded with a successful thermal EOR redevelopment. Average daily production from these properties increased from 50 BOE/D at acquisition in 2003 to 3,620 BOE/D in 2011. In 2012, we plan to expand the steam flood at our Poso Creek properties by drilling approximately 10 producing wells and six steam injection wells. Our Placerita field is located in Los Angeles County. In 2011, our efforts at Placerita were focused on the initiation of an Upper Kraft zone steam flood pilot and recompletion program. Average daily production at our Placerita properties increased to approximately 2,300 BOE/D in the fourth quarter of 2011 from less than 1,900 BOE/D in the third quarter of 2011. In 2012, we plan to drill six producing wells and continue our recompletion program in the Upper Kraft zone.

Average daily production from all SMWSS – Steam Floods assets was approximately 13,185 BOE/D in 2011 compared to 13,595 BOE/D in 2010.

NMWSS – Diatomite. Our NMWSS – Diatomite assets include our Diatomite and McKittrick properties and our North Midway-Sunset steam flood properties in the San Joaquin Valley. We received a new full-field development approval in late July 2011 from the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR) with respect to our Diatomite property. The approval contained operating requirements that were significantly more stringent than similar specifications contained in prior approvals from DOGGR. Implementation of these newer operating requirements negatively impacted the pace of drilling and steam injection in 2011, and this impact has continued into 2012. We are working constructively with DOGGR on the operating specifications to enable an increase in the pace of our development. On February 24, 2012, we received revisions to the July 2011 project approval letter, which, among other things, allow us to conduct mechanical integrity testing at least once every five years, rather than annually as provided in the original project approval letter. In addition, we are no longer required to cease cyclic steaming operations on wells located within 150 feet of a failed well bore, subject to demonstrating to DOGGR that steam injection into such surrounding wells will be confined to the Diatomite zone. Our estimates of well performance and ultimate recovery for the asset remain unchanged. We are currently assessing the impact of the revised project approval letter on the development and operations of our Diatomite properties. In 2011, we drilled 113 wells at our Diatomite property and expanded our infrastructure for the next phase of development. In 2012, we plan to drill approximately 70 new producing wells and 20 replacement wells at Diatomite. Average daily production from our Diatomite property was 3,154 BOE/D in 2011 compared to 2,721 BOE/D in 2010.

At our McKittrick property, we drilled 44 cyclic producing wells in 2011 in advance of a steam flood pilot expansion. We plan to steam cycle these new McKittrick wells and put them on production during the first quarter of 2012. We are currently in the final construction stages of our dehydration and steam generation facilities at our McKittrick property and plan to drill approximately 50 additional producing wells in 2012.

In 2011, we also drilled 51 wells at our North Midway-Sunset steam flood properties. In 2012, we plan to expand steam flood projects at our Fairfield, Pan and Main Camp properties, drilling approximately 35 producing wells and converting four wells to steam injection wells.

Average daily production from all NMWSS—Diatomite assets was approximately 4,210 BOE/D in 2011 compared to 3,527 BOE/D in 2010.

Permian. In 2010, we acquired approximately 20,000 net acres in the Wolfberry trend. In 2011, we acquired approximately 22,000 additional net acres in or adjacent to the Wolfberry trend, bringing our total Permian acreage to approximately 42,000 net acres. In 2011, we drilled 72 gross (69 net) wells and completed 80 gross (75 net) wells. Average daily production at our Permian properties was 5,600 BOE/D in the fourth quarter of 2011, despite a reduction of approximately 800 BOE/D related to natural gas curtailments in the fourth quarter. In 2012, we plan to operate a five rig drilling program and drill approximately 100 gross operated wells. Average daily production in our Permian properties was 4,420 BOE/D in 2011 compared to 1,225 BOE/D in 2010.

Uinta. In 2003, we established our initial acreage position in our Uinta properties near the Ashley National Forest, targeting the Green River formation that produces both light oil and natural gas. We acquired the Brundage Canyon leasehold in Duchesne County in Northeastern Utah, which consists of working interests in approximately 51,000 net acres on federal, tribal, and private leases. We have working interests in approximately 27,000 net acres and exploratory rights in approximately 45,000 net acres in the Lake Canyon project, which is located immediately west of our Brundage Canyon producing properties. In 2011, we drilled 54 gross (45 net) wells in our Uinta properties, which included 20 gross (20 net) wells in Brundage Canyon, 17 gross (17 net) wells in the Ashley National Forest and 17 gross (8 net) wells in Lake Canyon. Additionally, we deepened two existing wells in Brundage Canyon and one existing well in Lake Canyon. We participated in six non-operated Uteland Butte horizontal wells with our partner in Lake Canyon and drilled three Uteland Butte horizontal wells (two in Lake Canyon and one

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in Brundage Canyon). Of the 54 gross wells drilled in 2011, 12 tested the Wasatch formation. Results from the Wasatch test wells have been encouraging. We continue to monitor the progress of our initial water flood pilot in Brundage Canyon, which was implemented in the fourth quarter of 2009, and, in 2012, we plan to expand our second water flood pilot that was implemented in Brundage Canyon in the fourth quarter of 2010. Our Ashley National Forest Environmental Impact Study (EIS) continues to progress, although final approval continues to be delayed. We plan to run a three rig program in the Uinta in 2012, focused on developing areas of higher oil potential, including horizontal wells in the Uteland Butte and Brundage Canyon and commingled wells in the Green River and Wasatch formations. We estimate an inventory of 800-1,400 potential locations distributed across our entire Uinta leasehold. Average daily production in our Uinta properties was approximately 5,540 BOE/D in 2011 compared to 5,350 BOE/D in 2010.

Piceance. In 2006, we acquired two properties in the Piceance targeting the Williams Fork section of the Mesaverde formation. We have a 62.5% working interest in 6,300 gross acres on our Garden Gulch property, a 95% working interest in 4,300 gross acres and a 5% non-operating working interest in 89 wells on our North Parachute property. We have accumulated a sizable resource base, which should allow us to add significant proved reserves as we develop these assets. We have successfully drilled 111 gross wells (69 net) at our Garden Gulch property and 38 gross wells (36 net) on our North Parachute property since the acquisitions of those properties. During 2009, we began a 20 well completion program testing new completion designs and saw improved well performance in line with our expectations. During 2011, we completed nine wells utilizing these improved completion techniques, and results continue to meet our expectations. In January 2011, we renegotiated the agreement covering the North Parachute property such that we have until January 31, 2020 to complete our drilling obligations. See Note 10 to the Financial Statements. We are currently deferring drilling in the Piceance while we focus on higher return oil development opportunities in our portfolio. Average daily production in our Piceance properties was 24 MMcf/D in 2011 compared to 23 MMcf/D in 2010.

E. Texas. In 2008, we acquired certain interests in natural gas producing properties in Limestone and Harrison Counties in E. Texas. The Limestone County assets include seven productive horizons in the Cotton Valley and Bossier sands at depths between 8,000 and 13,000 feet. Additional potential exists in the Haynesville/Bossier shale. The Harrison County assets include five productive sands as well as the Haynesville/Bossier Shale, with average depths between 6,500 and 13,000 feet. In 2010, we completed an eight well Haynesville horizontal development program. We deferred drilling in E. Texas during 2011 and will defer drilling during 2012 while we focus on higher return oil development opportunities in our portfolio. Due to the impact of lower natural gas prices, we recorded an impairment of $625.0 million related to our E. Texas assets. See Notes 9 and 11 to the Financial Statements. Average daily production from the E. Texas assets was 26 MMcf/D in 2011 as compared to 31 MMcf/D in 2010.

Reserves

The following table presents our estimated quantities of proved reserves as of December 31, 2011:

	Estimated Proved Reserves(2)		
	Oil (MBOE)	Natural Gas (MMcf)	Total (MBOE)(1)
Developed	107,849	221,606	144,783
Undeveloped	78,031	312,673	130,143
Total proved—December 31, 2011	185,880	534,279	274,926

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.
(2) At December 31, 2011, all of our oil and natural gas reserves are attributable to properties within the United States.

At December 31, 2011, our estimated proved undeveloped reserves (PUDs) were 130.1 MMBOE, a decrease of 5% compared to 137.5 MMBOE at December 31, 2010. During 2011, approximately 26.8 MMBOE, or 19.5%, of our December 31, 2010 PUDs were converted into proved developed reserves as a result of investing approximately $345.4 million of drilling, completion and facilities capital. In addition, in 2011, we acquired 12.9 MMBOE of PUDs in the Wolfberry trend in the Permian. As a result of the SEC's five year development limitation on PUDs, we converted 20.5 MMBOE of PUDs to unproved reserves primarily due to changes in timing of our PUD development plans. Our drilling and completion activities in 2011, primarily related to our California, Permian and Utah assets, and engineering revisions, resulted in the addition of approximately 27.8 MMBOE of PUDs. We intend to convert the PUDs disclosed as of December 31, 2011 to proved developed reserves within five years of the date they were initially disclosed as proved undeveloped.

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Preparation of Reserves Estimates

Estimated proved reserves at December 31, 2011 were prepared by DeGolyer and MacNaughton (D&M), an independent petroleum engineering consulting firm that has provided consulting services throughout the world for over 70 years. See Exhibit 99.1—Report of DeGolyer and MacNaughton dated February 15, 2012.

Estimated proved reserves presented in the table above were calculated in accordance with the Securities and Exchange Commission's (SECs) "Modernization of Oil and Gas Reporting" rule which was first effective for December 31, 2009 reporting. These rules include calculating estimated proved reserves based on the average prices during the twelve-month period prior to the reporting date, with such prices determined as the unweighted arithmetic average of the first-day-of-the-month prices for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In addition, 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.

We maintain adequate and effective internal controls over the reserve estimation process. The reserves estimation process begins with our reserves coordinators, who are senior petroleum engineers and who are part of each asset team. The reservoir coordinators prepare, update and assemble information provided to D&M. Once all the relevant technical and support information has been assembled, D&M meets with our technical personnel to review field performance and future development plans. Following these reviews, D&M prepares independent reserve estimates and a final report based on the information we furnish to them. Our senior reservoir engineer oversees the reserve estimation process and has over 21 years of industry experience in the estimation and evaluation of reserve information. She holds a B.S. degree in Mechanical Engineering from South Dakota School of Mines and Technology. Our reserve data and our reserve estimation process are reviewed by our senior management and a subcommittee of the Audit Committee of our Board of Directors.

The lead technical person at D&M primarily responsible for overseeing the audit of our reserves is a Registered Professional Engineer in the State of Texas, is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists and has over 35 years of experience in oil and natural gas reservoir studies and reserves evaluations.

There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. See Part I, Item 1A—"Risk Factors," for a description of some of the risks and uncertainties associated with our business and reserves.

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Production, Average Sales Prices and Operating Costs

The table below includes information for each of our assets that we consider a single field and which contained 15% or more of our total proved reserves at the dates shown. See Part II, Item 6. "Selected Financial Data" and Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information regarding our production, average sales price and operating costs.

	Net Production Volumes(1)		Average Sales Price(2)		Average Operating Cost
	Oil (BOE/D)	Natural Gas (Mcf/D)	Oil ($/BOE)	Natural Gas ($/Mcf)	$/BOE
Year Ended December 31, 2011					
Total production—Continuing operations	34,771	65,498	$92.35	$4.09	$18.23
Diatomite	3,154	—	106.20	—	38.40
Permian	3,741	4,083	82.94	4.10	9.38
Piceance	86	23,472	65.04	4.13	9.40
Year Ended December 31, 2010					
Total production—Continuing operations	31,713	65,720	$67.61	$4.37	$15.95
Diatomite	2,721	—	75.03	—	32.08
South Midway-Sunset(3)	6,889	—	63.96	—	12.77
Piceance	62	22,681	64.14	4.25	8.94
Year Ended December 31, 2009					
Total production—Continuing operations	19,688	57,484	$50.73	$3.61	$14.66
Diatomite	3,093	—	57.00	—	21.98
South Midway-Sunset(3)	7,214	—	48.68	—	10.18
Piceance	43	18,981	45.56	3.35	9.05

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

(2) Excludes effects of derivative instruments.

(3) Includes only our Homebase and Formax properties, which we consider a single field and which contained 15% or more of our total proved reserves at the dates shown.

Productive Wells and Acreage

As of December 31, 2011, we had working interests in 3,038 gross (2,867 net) productive oil wells and 467 gross (282 net) productive natural gas wells. Productive wells include both producing wells and shut-in wells that are capable of producing.

The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2011. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and natural gas in economic quantities. Gross acreage represents acres in which we have a working interest, and net acreage represents our aggregate working interests in the gross acres.

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
California	6,352	5,829	832	741	7,184	6,570
Colorado	1,600	1,121	9,062	6,956	10,662	8,077

Nevada	840	771	4,455	3,997	5,295	4,768
Texas	15,500	12,125	43,572	34,339	59,072	46,464
Utah(1)	22,160	21,373	123,810	73,582	145,970	94,955
Wyoming	3,640	522	—	—	3,640	522
Kansas	—	—	54,764	53,790	54,764	53,790
Other	40	4	—	—	40	4
Total	50,132	41,745	236,495	173,405	286,627	215,150

(1) Excludes 45,000 net acres subject to drill-to-earn agreements.

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Future Acreage Expirations

If production is not established or we take no other action to extend the terms of the related leases, undeveloped acreage will expire over the next three years as follows:

	2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net
Utah	4,293	3,298	14,553	2,201	1,940	1,517
Texas(1)	205	444	1,409	1,806	10,972	9,031
Kansas	54,764	53,790	—	—	—	—
Total	59,262	57,532	15,962	4,007	12,912	10,548

(1) Expiring net acreage may be greater than expiring gross acreage when multiple undivided interests in the same gross acreage expire at different times.

The amounts in the table above represent the acreage that will expire if no further action is taken to extend. We currently intend to extend our acreage positions in Utah and Texas prior to expiration, either through development or through lease extensions. The expiring acreage in Kansas relates to a coalbed methane lease that will not be developed or renewed.

Drilling Activity

The following table sets forth our drilling activities for the following periods:

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells drilled:						
Productive	403	366	241	232	132	132
Dry	1	1	—	—	2	2
Exploratory wells drilled:						
Productive	1	1	—	—	—	—
Dry	3	3	1	1	—	—
Total wells drilled:						
Productive	404	367	241	232	132	132
Dry	4	4	1	1	2	2

We achieved a gross drilling success rate of 99.0%, 99.6% and 98.5% for the years ended December 31, 2011, 2010 and 2009. Gross drilling success represents the percentage of gross wells drilled that were not dry wells (defined as a well incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well).

As of December 31, 2011, we had 9 rigs drilling on our properties and we had 9 gross (8 net) wells in progress.

Marketing and Customers

We market the majority of the oil and natural gas production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our production to a variety of purchasers under oil and natural gas purchase contracts with daily, monthly, seasonal, annual or multi-year terms, all at market prices. The majority of our sales are to marketing companies or refiners. We typically sell production to a relatively small number of customers.

For the year ended December 31, 2011, sales to ExxonMobil Oil Corporation and Shell Trading (US) Company accounted for approximately 43% and 14%, respectively, of our revenue. Based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition, results of operations, or operating cash flows. However, due to possible refinery constraints in the Utah region, it is possible that the loss of a single refining customer in Utah could materially and adversely affect the marketability of a portion of our Utah crude oil volumes.

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Oil. Our oil production is collected in tanks and sold via pipeline or truck. Our oil contracts are priced either on local area oil postings or are based upon the NYMEX WTI, with location or transportation differentials. A substantial portion of our oil reserves are located in California, and approximately 49% of our production is attributable to heavy crude (generally 21 degree API gravity crude oil or lower). The market price for California crude differs from the established market indices in the U.S. due primarily to the higher refining costs associated with heavy crude and differences in supply origin at domestic refineries. As of December 31, 2011, over 87% of our California oil production was under contract with Shell Trading (US) Company and ExxonMobil Oil Corporation. Our contract with Shell Trading (US) Company continues through June 30, 2013, and our contract with ExxonMobil Oil Corporation renews automatically on a month-to-month basis, unless either party to the contract terminates upon 90 days' notice. Our remaining California production is under contract through December 2012 with a refiner in the Los Angeles basin.

In Utah, we are a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum amount of Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. See Item 1A. Risk Factors—"We may not be able to deliver minimum crude oil volumes required by our sales contract."

Natural Gas. Our natural gas is transported through our own and third party gathering systems and pipelines. We incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped and the fee charged by the third-party processor or transporter. In certain instances, we enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our natural gas volumes. During 2011, our Rocky Mountain natural gas production was sold into the eastern markets in Lebanon and Clarington, Ohio, while our natural gas production in Utah is generally priced relative to a Rocky Mountain Northwest Pipeline (NWPL) or Questar index price. Our natural gas produced in E. Texas is generally priced based on the Florida Zone 1 or the Natural Gas Pipeline Co. of America-Texok zone (NGPL Texok) index. Our natural gas produced in the Permian is priced based on the El Paso Permian index.

We enter into firm transportation contracts on interstate and intrastate pipelines to assure the delivery of our natural gas to market. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity
is used or not. Currently, our natural gas production is insufficient to fully utilize our contracted capacity on the Rockies Express, Wyoming Interstate, and Ruby pipelines. In California, we have firm transportation contracts to assure our ability to purchase a portion of our consumed natural gas outside of the California markets. The following table sets forth information about material long-term firm transportation contracts for pipeline capacity as of December 31, 2011:

Pipeline	From	To	Quantity (Avg. MMBtu/D)	Term	Demand charge per MMBtu		Remaining contractual obligation (in thousands)
Kern River Pipeline	Opal, WY	Kern County, CA	12,000	5/2003 to 4/2013	$0.58		$3,413
Rockies Express Pipeline	Meeker, CO	Clarington, OH	25,000	2/2008 to 1/2018	1.13	(1)	62,949
Rockies Express Pipeline	Meeker, CO	Clarington, OH	10,000	6/2009 to 11/2019	1.09	(1)	31,400
Questar Pipeline			2,500		0.17	(2)	79

	Brundage Canyon, UT	Salt Lake City, UT		9/2003 to 6/2012		
Questar Pipeline	Brundage Canyon, UT	Salt Lake City, UT	2,859	9/2003 to 6/2012	0.17	(2) 91
Questar Pipeline	Brundage Canyon, UT	Goshen, UT	5,000	9/2003 to 10/2022	0.26	5,087
Questar Pipeline	Chipeta Plant, UT	Various UT locations	6,200	7/2012 to 6/2020	0.17	(2) 3,165
Enbridge Pipeline	Limestone and Harrison Counties, TX	Orange, TX	Up to 55,000	4/2009 to 3/2012	0.22	277
Wyoming Interstate Company Pipeline	Meeker, CO	Opal, WY	35,000	8/2011 to 7/2021	0.31	38,335
Ruby Pipeline	Opal, WY	Malin, OR	35,000	8/2011 to 7/2021	0.95	118,741
Total			188,559			$263,537

(1) Based on weighted average cost.

(2) Subject to completion of planned expansion of the Chipeta Processing LLC natural gas plant. The expansion is expected to be completed and transportation will begin under the contract on July 1, 2012.

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Steaming Operations

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

Cogeneration Steam Supply. In pursuing our goal of being a cost-efficient heavy oil producer in California, we have consistently focused on minimizing our steam cost. We believe one of the main methods to keep steam costs low is through the ownership and efficient operation of three cogeneration facilities located on our properties. Two of these cogeneration facilities, a 38 megawatt (MW) and an 18 MW facility, are located on our SMWSS properties. We also own a 42 MW cogeneration facility, which is located on our Placerita property. 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. We also own 39 fully permitted conventional steam generators. The quantity of generators operated at any point in time is dependent on (i) the steam volume required to achieve our targeted production and (ii) the price of natural gas compared to the realized price of crude oil sold. In 2011, we added five additional steam generators, four for use in our ongoing development of our Diatomite property and one for use at our McKittrick property. In 2010, we added four additional steam generators for use in our ongoing development of our Diatomite assets. In 2009, we added three additional generators at our Diatomite property and one steam generator at our Poso Creek property.

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

Total BSPD capacity as of December 31, 2011 was as follows:

Steam generation capacity of conventional steam generators	133,429
Steam generation capacity of cogeneration plants	42,789
Additional steam purchased under contract with a third party	1,870
Total steam capacity	178,088

The average gross volume of steam injected in our operations for the years ended December 31, 2011 and 2010 was 133,404 BSPD and 116,956 BSPD, respectively.

During December 2011, approximately 80% of the natural gas we purchased to generate steam and electricity was based upon California indices. We pay distribution/transportation charges for the delivery of natural gas to our various locations where we use the natural gas for steam generation purposes. In some cases, this transportation cost is embedded in the price of the natural gas we purchase. Approximately 20% of the volume of natural gas purchased to generate steam and electricity was purchased in the Rockies and moved to the Midway-Sunset field using our firm transportation capacity on the Kern River Pipeline. This natural gas has historically been purchased based upon the Rocky Mountain NWPL index.

	2011	2010	2009
Average SoCal Border Monthly Index Price per MMBtu	$4.10	$4.34	$3.59

Average PG&E Citygate Monthly Index Price per MMBtu	4.29	4.66	4.17
Average Rocky Mountain NWPL Monthly Index Price per MMBtu	3.80	3.94	3.09

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Historically we have been a net producer of natural gas and have benefited operationally when natural gas prices increase. Our production of natural gas has, in the past, provided a form of natural hedge against rising steam costs. As our natural gas production continues to decrease and our use of natural gas for steaming operations increase, we may become a net consumer of natural gas and would no longer benefit operationally when natural gas prices increase. The following table shows our average and estimated average amount of production, consumption and hedged volumes (in average MMBtu/D) for the following years:

	Estimated 2012	2011	2010
Natural gas produced	51,190	65,500	65,720
Natural gas consumed in operations			
Cogeneration operations	26,500	25,087	27,083
Conventional steam generators	49,000	34,377	27,108
Total natural gas consumed in operations	75,500	59,464	54,191
Less: Estimated natural gas volumes consumed to produce electricity(1)	(16,000)	(15,229)	(18,171)
Net estimated natural gas consumed in steam generation	59,500	44,235	36,020
Natural gas volumes hedged	15,000	15,000	19,000
Estimated net (deficit) excess of natural gas produced, consumed, and hedged	(23,310)	6,265	10,700

(1) Estimate is based on the historical allocation of fuel costs to electricity.

Electricity

Generation. The total net electrical generation capacity of our three cogeneration facilities during 2011 was approximately 93 MW, of which we consumed approximately 7 MW for use in our operations. Each facility is centrally located on certain of our oil producing properties. Thus the steam generated by each facility is capable of being delivered to numerous wells that require steam for the EOR process. Our investment in our cogeneration facilities has been for the express purpose of lowering the steam costs in our heavy oil operations and securing operating control of the respective steam generation. Expenses of operating the cogeneration plants are analyzed regularly to determine whether they are advantageous versus conventional steam generators. Cogeneration costs are allocated between electricity generation and oil and natural 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 natural gas operations using a similar allocation method.

Sales Contracts. We sell electricity produced by our cogeneration facilities to two California public utilities: Southern California Edison Company (Edison) and Pacific Gas and Electric Company (PG&E), under long-term contracts approved by the California Public Utilities Commission (CPUC). These contracts are referred to as standard offer (SO) power purchase agreement (PPA) 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. We currently sell energy and capacity to PG&E and Edison under interim extensions of legacy PPAs with those utilities. These legacy PPAs were originally ordered by the CPUC in the 1980s in its implementation of the Public Utilities Regulatory Policy Act of 1978, as amended (PURPA). As these legacy PPAs expired over the last 10 years, there has been considerable pressure by the investor owned utilities

(IOUs) to require qualifying facilities (QFs), such as our cogeneration plants, to bid for new contracts against other resources in competitive solicitations. The administratively determined energy and capacity prices under these standard offer contracts have also been the subject of litigation in various regulatory and legal proceedings for more than 10 years. In an effort to resolve a broad range of issues, the various parties involved, including us, entered into settlement discussions resulting in a Global Settlement that became effective on November 23, 2011. Among other things, the Global Settlement resolved all claims by the IOUs for retroactive payment adjustments against QFs, including claims against us, made available new standard form contracts, revised SRAC energy prices and established a transition period to allow QFs to secure new long-term agreements through competitive solicitations. Our current legacy extension PPAs with Edison for our Placerita Units 1 and 2 are scheduled to terminate on or about March 22, 2012, at which time we intend to enter into a Transition Contract for the combined output of the two units. The Transition Contract is intended to be a bridge agreement to allow QFs to bid against other CHP facilities for long-term contracts with the IOUs and is similar to our current SO contracts, but with updated regulatory requirements and more stringent scheduling and performance requirements. All Transition Contracts will terminate no later than June 30, 2015, but may be terminated earlier if we elect to bid into a competitive CHP solicitation and are awarded a contract based on our bid. There is no assurance that we will be successful in bidding for long-term replacement contracts prior to the termination of our Transition Contract.

Our current PPAs with PG&E for our Cogen 18 facility and our Cogen 38 facility are scheduled to terminate on March 31, 2012. Because the rated capacity of our Cogen 18 facility is less than 20 MW, it will continue to be eligible for a PURPA contract under which it will be paid the prevailing CPUC-determined SRAC price and either a firm or as-available capacity payment at our discretion. In addition, we will have the option to competitively bid the energy and capacity from our Cogen 18 facility into various competitive solicitations that will be open only to CHP facilities. Upon the termination of the PPA for Cogen 18, we anticipate that we will enter into a new contract with PG&E pursuant to PURPA with a term of up to seven years. Upon the termination of the PPA for our Cogen 38 facility, we anticipate that we will enter into a Transition Contract with PG&E that will terminate no later than June 30, 2015. We also intend to bid into one or more of the CHP only solicitations that were issued by Edison and PG&E in December 2011. For existing facilities, such as ours, the maximum term of a PPA awarded in a competitive IOU solicitation is seven years. Beginning in 2015, the energy prices we will be paid will be based on market prices for electricity. See Item 1A. Risk Factors-"We are dependent on our cogeneration facilities and deteriorations in the electricity market and regulatory changes in California may materially and adversely affect our financial condition, results of operations and operating cash flows."

Facility and Contract Summary

Location and Facility	Type of Contract (4)	Purchaser	Contract Expiration		Approximate Megawatts Available for Sale(1)	Approximate Megawatts Consumed in Operations(1)	Approximate Barrels of Steam Per Day
Placerita							
Placerita Unit 1	SO2	Edison	Mar-12	(2)	20	—	6,500
Placerita Unit 2	SO1	Edison	Mar-12	(2)	17	4	6,500
S. Midway							
Cogen 18	SO1	PG&E	Mar-12	(3)	11	4	6,600
Cogen 38	SO1	PG&E	Mar-12	(2)	37	—	18,500

(1) Assumes operations at full capacity with no interruptions.
(2) We anticipate the current contract will be replaced by a transition contract expiring June 30, 2015.
(3) We anticipate the current contract will be replaced by a PURPA contract with a term of up to 7 years.
(4) SO1 contracts pay only "as available" capacity rates and SO2 contracts pay firm capacity rates.

Competition

The oil and natural gas industry is highly competitive. As an independent producer, we have little control over the price we receive for our 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 natural gas properties and prospective acreage. Although many of these competitors have greater financial and other resources than we have, we are in a position to compete effectively due to our business strengths.

Title to Properties

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

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Employees

As of December 31, 2011, we had 317 full-time employees. We also contract for the services of independent consultants involved with land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by a collective bargaining agreement. Our relations with our employees are good.

Offices

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

Available Information

Our website, located at http://www.bry.com, can be used to access recent news releases and Securities and Exchange Commission (SEC) filings, crude oil price postings, hedging summaries, our Annual Report, Proxy Statement, Board Committee Charters, Corporate Governance Guidelines, Code of Business Conduct and Ethics, the Code of Ethics for Senior Financial Officers, and other items of interest. Information on our website is not incorporated into this report. SEC filings, including supplemental schedules and exhibits, can also be accessed free of charge through the SEC website at http://www.sec.gov.

Environmental Matters and Other Regulations

General. Our operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Our operations are subject to the same environmental laws and regulations as other companies in the oil and natural gas exploration and production industry. These laws and regulations:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within environmentally sensitive areas, wilderness, wetlands and other protected areas;
- require measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations; and
- with respect to operations affecting federal lands or leases, require time-consuming environmental analysis with uncertain outcomes.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost and timing of doing business and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay of oil and natural gas operations or more stringent and costly permitting, well drilling, construction, completions and water management activities, or waste handling, disposal and clean-up requirements for the oil and natural gas industry could have a significant impact on our operating costs.

We believe that, in all material respects, we are in compliance with, and have complied with, all applicable environmental laws and regulations. We have made and will continue to make expenditures in our efforts to comply with all environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with governmental regulations. We believe that our continued compliance with existing requirements has been accounted for and will not have a material and adverse impact on our financial condition, results of operations and operating cash flows. However, we cannot predict the passage of or quantify the potential impact of any more stringent future laws and regulations at this time. For the year ended December 31, 2011, we did not incur any material capital expenditures for remediation or retrofit of pollution control equipment at any of our facilities.

Some of the more significant environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Departments of Interior and

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Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an environmental assessment prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed EIS that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that may trigger the requirements of NEPA. This process has the potential to delay or limit the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Waste Handling. The Resource Conservation and Recovery Act (RCRA) and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” and the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency (EPA), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil, natural gas, or geothermal energy constitute “solid wastes,” which are regulated under the less stringent, non-hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration and production wastes as “hazardous wastes.” In September 2010, an environmental organization petitioned the EPA to reconsider certain RCRA exemptions for exploration and production wastes but, to date, the EPA has not taken action on the petition.

We believe that we are in compliance in all material respects with the requirements of RCRA and related state and local laws and regulations, and that we have held, and continue to hold, all necessary approvals, permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we believe that the current costs of managing waste as presently classified are reflected in our budget, any more stringent legislative or regulatory reclassification of oil and natural gas exploration and production waste could increase our costs to manage and dispose of such waste.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the “Superfund” law, imposes strict, joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for a release or threatened release of a “hazardous substance” into the environment. These persons include the current and past owner or operator of the disposal site, or site where the release or threatened release of a “hazardous substance” occurred, and companies that disposed or arranged for the disposal of the hazardous substance. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, could be subject to CERCLA. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA for all or part of the costs to clean up sites at which such “hazardous substances” have been released.

Water Discharges. The federal Water Pollution Control Act (Clean Water Act) and comparable state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Air Emissions. The federal Clean Air Act (CAA) and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs. These laws and the implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other “greenhouse gases” (GHGs) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of

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the CAA. The EPA recently adopted two sets of rules regulating GHG emissions under the CAA, one that requires a reduction in emissions of GHGs from motor vehicles and the other that regulates emissions of GHGs from certain large stationary sources under the Clean Air Act's Prevention of Significant Deterioration and Title V permitting programs. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among other things, certain onshore oil and natural gas production facilities, on an annual basis.

In addition, legislation has from time to time been introduced in the United States Congress that would establish measures restricting GHG emissions in the United States. At the state level, almost one half of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. The State of California has adopted legislation that caps California's GHG emissions at 1990 levels by 2020, and the California Air Resources Board (CARB) has implemented mandatory reporting regulations and instituted early action measures in an effort to reduce GHG emissions prior to January 1, 2012. On October 20, 2011, California became the first state to adopt a cap and trade program to reduce GHG emissions. The new regulations, which will take effect in 2013, will require us to continue to report our GHG emissions and will set maximum limits or caps on total emissions of GHGs from all industrial sectors, including the oil and natural gas extraction sector of which we are a part, that are subject to the cap and trade regulation. The cap will decline annually thereafter through 2020. We will be required to obtain compliance instruments for each metric tonne of GHG that we emit, in the form of allowances (each the equivalent of one ton of carbon dioxide) or qualifying offset credits. The availability of allowances will decline over time in accordance with the declining cap, and the cost to acquire such allowances may increase over time. We are currently assessing the impact of these regulations on our operations, including the costs to acquire allowances and to reduce emissions. Our early estimates indicate that, based on our understanding of the current market price of allowances, the manner in which cost-free allowances are to be distributed by CARB to the oil and natural gas extraction industry and our current production and emissions estimates, among other factors, our cost of acquiring allowances beginning in 2013 may be in the range of $2.00-3.00 per barrel. The actual cost to acquire allowances will depend on the market price for such allowances at the time they are purchased, the distribution of allowances among various industry sectors and our ability to limit our GHG emissions and implement cost-containment measures. The cap and trade program is currently scheduled to be in effect through 2020.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition, results of operations and operating cash flows.

Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act (SDWA) and is developing guidance documents related to this newly asserted regulatory authority. In addition, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate a rulemaking under the Toxic Substances Control Act relating to chemical substances and mixtures used in oil and natural gas exploration and production. Moreover, legislation has been introduced before Congress to repeal an exemption in the federal SDWA for the underground injection of hydraulic fracturing fluids near drinking water sources. If adopted, the legislation would require the reporting and public disclosure of chemicals used in the fracturing process. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Further, if enacted, the FRAC Act could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements.

Certain states in which we operate, including Texas and Colorado have adopted, and other states are considering adopting, regulations that could impose increased regulatory oversight of hydraulic fracturing through additional permit requirements, public disclosure, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For example, the Railroad Commission of Texas adopted rules in December 2011 requiring disclosure of certain information regarding the components used in the hydraulic fracturing process. In addition to state laws,

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local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the EPA announced on October 20, 2011 that it is launching a study of wastewater resulting from hydraulic fracturing activities and currently plans to propose pretreatment regulations by 2014. The U.S. Department of Energy is also conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Moreover, the U.S. Department of the Interior is considering public disclosure, well testing and monitoring requirements for hydraulic fracturing on federal lands. Also, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise.

Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and natural gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured natural gas wells. These standards include the reduced emission completion (REC) techniques developed in the EPA's Natural Gas STAR program along with the pit flaring of natural gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. Final action on the proposed rules is expected no later than April 3, 2012.

The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete natural gas wells in shale formations, and obtain permits, and could increase our costs of compliance and doing business.

Endangered Species. The Endangered Species Act (ESA) may restrict activities that may affect endangered and threatened species or their habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Federal Energy Regulation. The enactment of the PURPA 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. Second, FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's avoided cost and that the utility sell back-up power to the QF on a non-discriminatory basis. The term “avoided cost” is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The Energy Policy Act of 2005 amended PURPA to allow a utility to petition FERC to be relieved of its obligation to enter into any new contracts with QFs if FERC determines that a competitive wholesale electricity market is available to QFs in the service territory. Upon the effectiveness of the Global

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Settlement on November 23, 2011, the California utilities have been relieved of their PURPA obligation to enter into new contracts with cogeneration QFs larger than 20 MW. However, under the Global Settlement those utilities will be required to offer standard form Transition contracts pursuant to CPUC jurisdiction to facilities larger than 20 MW, for a term ending no later than June 30, 2015.

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

Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, federal, state, local, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production. Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribes also regulate one or more of the following:

- 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 and other third parties;
- wildlife management and protection;
- the protection of archaeological and paleontological resources;
- property mitigation measures;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws can establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction.

Natural Gas Sales and Transportation. Section 1(b) of the Natural Gas Act (NGA) exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional 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.

FERC requires certain participants in the natural gas market, including natural gas gatherers and marketers, which engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. Should we

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fail to comply with this requirement 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.

Operations on Native American Reservations. A portion of our leases and drill-to-earn arrangements in the Uinta are, and some of our future leases in this and other areas may be, regulated by Native American tribes. In addition to regulation by various federal, state and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations. Various federal agencies within the U.S. Department of the Interior, particularly the Minerals Management Service and the Bureau of Indian Affairs, as well as the EPA, together with each Native American tribe, promulgate and enforce regulations pertaining to oil and natural gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, Tribal employment and contractor preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and Bureau of Land Management. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership. In addition, we are subject to the terms and conditions of Native American oil and natural gas leases, as well as fees, taxes, obligations and other issues unique to oil and natural gas ownership and operations within Native American reservations. These laws, regulations and other issues present unique risks which may impose additional requirements on our operations, cause delays in obtaining necessary approvals or permits, or result in losses or cancellations of our oil and natural gas leases, which in turn may materially and adversely affect our operations on Native American tribal lands.

Item 1A. Risk Factors

Oil and natural gas prices are volatile, and declines in prices could materially and adversely affect our business, financial condition, results of operations and operating cash flow. Our future financial condition, revenues, results of operations, rate of growth and the carrying amount of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil and natural gas prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil and natural gas are subject to a variety of factors beyond our control, including:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign oil and natural gas;

- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption;
- variations between product prices at sales points and applicable index prices; and
- worldwide economic conditions.

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These factors and the volatility of oil and natural gas markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. Declines in oil and natural gas prices would reduce our revenues and could also reduce the amount of oil and natural gas that we can produce economically, which could materially and adversely affect our financial condition, results of operations, and operating cash flow.

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

Proved oil and natural gas properties are reviewed for impairment on a field-by-field basis, annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and natural gas properties and compare these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, and discount rates commensurate with the risk associated with realizing the projected cash flows. Due to the impact of lower natural gas prices, we recorded an impairment of $625.0 million related to our E. Texas natural gas assets. See Notes 9 and 11 to the Financial Statements.

The U.S. natural gas price environment remained depressed and volatile in 2011 as NYMEX Henry Hub (HH) spot prices declined 32% from $4.41 per MMBtu at December 31, 2010 to $2.99 per MMBtu at December 31, 2011. In the fourth quarter of 2011, the NYMEX HH five-year future strip (the average of the settlement prices of the next 60 months' futures contracts) decreased approximately 15% from $4.97 at September 30, 2011 to $4.23 at December 31, 2011. If the price of natural gas futures continues to decrease during 2012, the estimated undiscounted future cash flows for our natural gas properties may fall below the carrying amount for such assets, and, in such case, we would be required to reduce the carrying amount our natural gas properties to estimated fair value.

The borrowing base of our senior secured revolving credit facility is subject to semi-annual redeterminations in April and October of each year, based on the value of our oil and natural gas properties, in accordance with the lenders' customary procedures and practices. We and the lenders each have a right to one additional redetermination each year. As of December 31, 2011, the borrowing base under our credit facility was $1.4 billion and total lender commitments were $1.2 billion. Declines in oil or natural gas prices in the future could limit our borrowing base and reduce our ability to borrow under our credit facility. Additionally, divestitures of properties could result in a reduction of our borrowing base.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities, replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy. The oil and natural gas industry is capital intensive. We require substantial capital expenditures to conduct our exploration, development, and production operations, engage in acquisition activities, and replace our production. Historically, we have funded our capital expenditures through a combination of our cash flows from operations, borrowings under our senior secured revolving credit facility and the capital markets. Our cash flow from operations and access to capital are subject to a number of factors, some of which are outside our control. These factors include, among others:

- the value and performance of our debt and equity securities;
- the credit ratings assigned to our debt by independent rating agencies;
- domestic and global economic conditions; and
- conditions in the domestic and global financial markets.

If our revenues or the borrowing base under our credit facility decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, seek additional financing. However, our credit facility places certain restrictions on our ability to obtain new financing, and we may not be able to obtain new financing on terms favorable to us, or at all. If cash generated by operations or borrowings under our credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our exploration and development activities, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves as well as our financial condition, results of operations and operating cash flows.

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The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Estimating accumulations of oil and natural gas is a complex process that relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC.

Actual future production, oil and natural gas prices, revenues, production taxes, development expenditures, operating expenses, and quantities of producible oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially and adversely affect the estimated quantities of and present values related to our proved reserves, and the actual quantities and present values may be less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development activity, prevailing oil and natural gas prices, costs to develop and operate properties, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties.

Further, it should not be assumed that any present value of future net cash flows from our estimated proved reserves represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our estimated proved reserves on first-day-of-month average oil and natural gas prices for the twelve-month period preceding the estimate and on costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations and, or taxes.

Approximately 47% of our total estimated proved reserves at December 31, 2011, were undeveloped, and those reserves may not ultimately be developed. At December 31, 2011, approximately 47% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated. Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could materially and adversely affect our financial condition, results of operations and operating cash flows.

In addition, 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. These requirements may limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Material downward adjustments to our estimated proved reserves could materially and adversely affect our financial condition, results of operations, and operating cash flows.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated. Our future oil and natural gas production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves and efficiently developing and exploiting our current reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

Recent regulatory changes in California have and may continue to materially and adversely impact our production and operating costs related to our Diatomite assets. Recent regulatory changes in California have impacted our Diatomite production. In 2010, Diatomite production decreased significantly due to the inability to drill new wells pending the receipt of permits from DOGGR. We received a new full-field development approval in late July 2011 from the DOGGR with respect to our Diatomite assets. The approval contained operating requirements that were significantly more stringent than similar specifications contained in prior approvals from DOGGR, including operating, response and preventative requirements relating to mechanical integrity testing and responses to integrity issues and surface expressions, among others. Implementation of these new operating requirements negatively impacted the pace of drilling and steam injection in 2011, and increased our operating

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costs for our Diatomite assets. The new requirements have continued to affect our operations into 2012, and may have lasting impacts on our operations in the future. On February 24, 2012, we received revisions to the July 2011 project approval letter amending certain requirements in such letter. For a description of the February 2012 revisions, see Item 1., "Business—Properties— NMWSS – Diatomite." We are currently assessing the impact of the revised project approval letter on the development and operations of our Diatomite properties. We may not be successful in streamlining the review process with DOGGR or in taking additional steps to more efficiently manage our operations to avoid additional delays. In addition, DOGGR may impose additional operational restrictions or requirements. In such case, we may experience additional delays in production and increased operating costs related to our Diatomite assets. Average daily production for our Diatomite assets was 3,154 BOE/D during 2011.

Our heavy crude oil in California may be less economic than lighter crude oil. As of December 31, 2011, approximately 44% of our proved reserves, or 120.5 million barrels, consisted of heavy oil, and light crude oil represented 24% of our proved reserves. Heavy crude oil historically sells for a discount to light crude oil, as more complex refining equipment is required to convert heavy oil into high value products. Additionally, most of our crude oil in California is produced using steam injection. This process is generally more costly than primary and secondary recovery methods.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results. We have significant concentrations of credit risk with the purchasers of our oil and natural gas. For example, all of our oil produced in the Utah region is sold under a long-term contract to a single refiner. Due to the terms of supply agreements with our customers, we may not know that a customer is unable to make payment to us until months after production has been delivered. If the purchasers of our oil and natural gas become insolvent, we may be unable to collect amounts owed to us. Due to refinery constraints in the Utah region, it is possible that the loss of a single refining customer in Utah could impact the marketability of a portion of our Utah crude oil volumes.

Drilling is a high-risk activity and, as a result we may not be able to adhere to our proposed drilling schedule, or our drilling program may not result in commercially productive reserves. Our future success will partly depend on the success of our drilling program. The future cost or timing of drilling, completing and producing wells is inherently uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- well integrity issues and surface expressions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- changes in regulations;
- compliance with governmental or landowner requirements;
- availability, costs and terms of contractual arrangements with respect to leases, pipelines and related facilities to gather, process and compress, transport and market oil and natural gas; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

In addition, our drilling plans require drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays which jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a material and adverse effect on our ability to explore on or develop our properties.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel. The demand for qualified and experienced field personnel to drill wells and conduct field operations such as geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future. In addition, the availability of drilling rigs can vary significantly from region to region at any particular time. Although

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land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region.

We may be unable to make attractive acquisitions or successfully integrate acquired operations, and any inability to do so may disrupt our business and hinder our ability to grow. Our business strategy has emphasized growth through strategic acquisitions. 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. In addition, we may have difficulty integrating the operations, systems, management and other personnel and technology of acquired assets or businesses with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

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

There may be threatened or contemplated claims against the assets or businesses we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, on acquisitions. We may 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. If we fail to discover breaches or defects prior to closing, we may incur significant unknown liabilities, including environmental liabilities, for which we would have limited or no contractual remedies or insurance coverage.

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

We may incur material losses and be subject to material liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks. Oil and natural gas operations are subject to many risks, including fires, explosions, well blowouts, uncontrollable flows of oil and natural gas, formation water or drilling fluids, adverse weather, freezing conditions in our various regions, natural disasters, pipe or cement failures, casing collapse, embedded oilfield drilling and service tools, formations with abnormal pressures, major equipment failures, including cogeneration facilities and, pollution, releases of toxic gas, and other environmental risks and hazards. If any of these types of events occurs, we could sustain material losses.

Under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease, or operate. As a result, we may incur material liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.

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We maintain insurance against some, but not all, of these potential risks and losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. We currently have insurance policies covering our operations that include coverage for general liability, excess liability, physical damage to our oil and natural gas properties, operational control of wells, oil pollution, third-party liability, workers' compensation and employers' liability and other coverages. 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. The occurrence of an event not fully covered by insurance could materially and adversely affect our financial condition, results of operations and operating cash flows.

Our use of hedging transactions could result in financial losses or reduce our earnings. To reduce our exposure to fluctuations in oil and natural gas prices, we have entered into and expect in the future to enter into derivative instruments (or hedging contracts) for a portion of our anticipated oil and natural gas production or natural gas consumption. Our hedging transactions expose us to certain risks and financial losses, including, among others the risk that we may be limited in receiving the full benefit of increases in oil and natural gas prices as a result of these transactions, and that we may hedge too much or too little production or consumption depending on how oil and natural gas prices fluctuate in the future.

Due to the volatility of oil and natural gas prices, we may be required to recognize unrealized gains and losses (non-cash changes in fair value) on derivative instruments as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period to period estimates and will be a function of the actual price of the commodities on the settlement date of the derivative instrument. We expect that commodity prices will continue to fluctuate in the future and, as a result, our periodic financial results will continue to be subject to fluctuations related to our derivative instruments.

Our financial counterparties may be unable to satisfy their obligations. We rely on financial institutions to fund their obligations under our credit facility and make payments to us under our commodity hedging contracts. Currently, all of our outstanding commodity derivative instruments are with lenders or affiliates of the lenders under our credit facility. 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 and materially and adversely affect our ability to fund capital expenditures and make acquisitions. If our financial counterparties are unable to make payments under our commodity hedging contracts, our cash flow will be reduced.

A widening of commodity differentials may materially and adversely impact our revenues and our economics. The oil and natural gas we produce are priced in the local markets where production occurs based on local or regional supply and demand factors as well as other local market dynamics such as regional storage capacity and transportation. The prices that we receive for our oil and natural gas production are generally lower than the relevant benchmark prices, such as NYMEX or Brent, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential.

We may be unable to accurately predict oil and natural gas differentials, which may widen significantly in the future. Numerous factors may influence local commodity pricing, such as refinery capacity, pipeline takeaway capacity and specifications, localized storage capacity, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be materially and adversely impacted by a widening differential on the products we sell. Our commodity hedging contracts are typically based on West Texas intermediate (WTI) or natural gas index prices. As a result, we may be subject to “basis risk” if the differential on products we sell widens from the benchmarks used in our commodity hedging contracts. Additionally, regional capacity and storage issues may cause benchmark prices to become disconnected from regional oil and natural gas prices which may materially and adversely affect the effectiveness of our hedges based on such indices. Insufficient pipeline capacity, storage capacity or trucking capability and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and natural gas producing areas. Increases in the differential between benchmark prices for oil and natural gas and the wellhead price we receive could materially and adversely affect our financial condition, results of operation, and operating cash flows.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production. Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities, trucking capability and refineries owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of oil and natural gas pipelines, gathering system capacity, processing facilities or refineries. If we experience interruptions or loss of pipeline or access to gathering systems that impact a substantial amount of our production, it could have a material and adverse impact on our financial condition, results of operation, and operating cash flows.

We may not be able to deliver minimum crude oil volumes required by our sales contract. Production volumes from our Uinta properties over the next several years are uncertain, and there is no assurance that we will be able to consistently meet the minimum required volume under our refining contract relating to our production from these properties. During the term of the contract, the minimum number of delivered barrels is 5,000 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 3,390 Bbl/d during 2011.

A shortage of natural gas in California could materially and 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 materially and adversely impacted.

We are dependent on our cogeneration facilities and deteriorations in the electricity market and regulatory changes in California may materially and adversely affect our financial condition, results of operations and operating cash flows. We are dependent on several cogeneration facilities that, combined, provide approximately 24% of our steam capacity as of December 31, 2011. These facilities are dependent on reasonable contracts for the sale of electricity. Market fluctuations in electricity prices and regulatory changes in California could adversely affect the economics of our cogeneration facilities and the corresponding increase in the price of steam could significantly impact our operating costs. If we are unable to enter into new or replacement contracts or were to lose existing contracts, we may be unable to meet our 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 could materially and adversely affect our financial condition, results of operations and operating cash flows. For a more detailed discussion of our electricity sales contracts, see Part I, Item 1, "Business-Electricity."

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

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

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Competition within our industry is intense and may materially and adversely affect our operations. We operate in a highly competitive environment. We compete with major and independent oil and natural gas companies in acquiring desirable oil and natural gas properties and in obtaining the equipment and labor required to develop and operate such properties. We also compete with major and independent oil and natural gas companies in the marketing and sale of oil and natural gas. Many of our competitors are larger, fully integrated energy companies that have financial, staff, and other resources substantially greater than ours, may be less leveraged than we are and have a lower cost of capital. As a result, these companies may have greater access to capital and may be able to pay more for development prospects and producing properties, or evaluate and bid for a greater number of properties and prospects than our financial and staffing resources permit. These larger companies may also 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. From time to time, we have to compete with financial investors in the property acquisition market, including private equity sponsors with more funds and access to additional liquidity. Many of these competitors have financial and other resources substantially greater than ours.

In addition, oil and natural gas producers are increasingly facing competition from providers of alternative energy, and government policy may favor those competitors in the future. We can give no assurance that we will be able to compete effectively in the future which could materially and adversely affect our financial condition, results of operations and operating cash flows.

Our oil and natural gas operations are subject to various environmental and other governmental laws and regulations that may materially affect our operations. Our oil and natural gas operations are subject to various U.S. federal, state, local and Tribal laws and regulations. These laws and regulations may be changed in response to economic, political or other conditions. There can be no assurance that present or future regulations will not materially and adversely affect our business and operations.

Many of the laws and regulations to which our operations are subject include those relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. In particular, regulation of GHG emissions by Congress, the EPA, or various other legislative or regulatory bodies in the United States could have an adverse effect on our operations and demand for the oil and natural gas that we produce. In addition, we could incur material expenditures complying with environmental laws and regulations, including future environmental laws and regulations which may be more stringent including, for example, the regulation of GHG emissions under new federal legislation, the federal Clean Air Act, or state or regional regulatory programs. In addition, changes in interpretations of or enforcement of existing laws may cause us to incur substantial expenditures. Operating in densely populated regions may expose us to additional risk of regulation, as well as claims by property owners and others affected by such operations. See Part I, Item 1, "Business—Environmental Matters and Other Regulations" for more detail on both current and potential governmental regulation.

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the Federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. For example, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel under the SDWA's Underground Injection Control Program and is developing guidance documents related to this newly asserted regulatory authority. In addition, both Texas and Colorado have adopted public disclosure regulations requiring varying degrees of disclosure of the constituents in hydraulic fracturing fluids. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to perform hydraulic fracturing, complete oil and natural gas wells in shale formations, and obtain permits, and could increase our costs of compliance and doing business. For a more detailed discussion of hydraulic fracturing matters impacting our business, see Part I, Item 1, “Business—Environmental Matters and Other Regulations.”

The loss of key personnel could materially and 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 materially and 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.

Restrictions in our existing and future debt agreements could limit our growth and our ability to respond to changing conditions. Agreements governing our outstanding debt restrict our ability to, among other things:

- incur, assume or guarantee additional indebtedness or issue redeemable stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes;
- make loans and other types of investments;
- incur liens;
- sell or otherwise dispose of assets;
- consolidate or merge with or into, or sell substantially all of our assets to, another person;
- make capital expenditures or acquire assets or businesses;
- enter into transactions with affiliates; and
- enter into new lines of business.

In addition, our credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. Our ability to borrow under our credit facility is dependent upon the quantity of proved reserves attributable to our oil and natural gas properties and the respective projected commodity prices as determined by the lenders under our credit facility. Our ability to meet these covenants or requirements may be affected by events beyond our control, and we cannot assure you that we will satisfy such covenants and requirements.

A downgrade in our credit rating could materially and adversely impact our cost of and ability to access capital. Our access to credit and capital markets also depends on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access capital or financial markets in the future, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information required by Item 2. Properties is included under Part I, Item 1, "Business—Properties."

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Item 3. Legal Proceedings

While we are, from time to time, a party to certain lawsuits in the ordinary course of business, we do not believe any of such existing lawsuits will have a material adverse effect on our operations, financial condition, or operating cash flows. For a description of legal matters see "Legal Matters" in Note 10 to the Financial Statements, which descriptions are incorporated by reference herein.

Item 4. Mine Safety Disclosure.

Not applicable.

Executive Officers

Presented below is information about our executive officers as of December 31, 2011. There are no family relationships between any of the executive officers and members of the Board of Directors.

ROBERT F. HEINEMANN, 58, has been President and Chief Executive Officer since June 2004. Mr. Heinemann was Chairman of the Board and interim President and Chief Executive Officer from April 2004 to June 2004. From December 2003 to March 2004, Mr. Heinemann acted as the director designated to serve as the presiding director at executive sessions of the Board in the absences of the Chairman and as liaison between the independent directors and the CEO. Mr. Heinemann joined the Board in March of 2002. From 2000 until 2002, Mr. Heinemann served as the Senior Vice President and Chief Technology Officer of Halliburton Company and as the Chairman of the Halliburton Technology Advisory Committee. He was previously with Mobil Oil Corporation (Mobil) where he served in a variety of positions for Mobil and its various affiliate companies in the energy and technical fields from 1981 to 1999, with his last responsibilities as Vice President of Mobil Technology Company and General Manager of the Mobil Exploration and Producing Technical Center.

DAVID D. WOLF, 41, has been Executive Vice President and Chief Financial Officer since August 2008. Mr. Wolf was previously employed by JPMorgan from 1995 to 2008 where he served as a Managing Director in JPMorgan's Oil and Gas Group and advised on numerous equity, debt and M&A transactions in the energy industry.

MICHAEL DUGINSKI, 45, 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, 51, 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.

GEORGE W. CIOTTI, 48, was promoted to Vice President of Rocky Mountain Production effective January 1, 2012. Mr. Ciotti was Vice President, Corporate Development from January 2010 until December 2011. Mr. Ciotti was

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

WALTER B. AYERS, 68, has held the position of Vice President of Human Resources since May 2006. Mr. Ayers was previously a private consultant to the energy industry from January 2002 until his employment with the Company. Mr. Ayers served as a Manager of Human Resources for Mobil Oil Corporation from June 1965 until December 2000.

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SHAWN M. CANADAY, 36, has held the position of Vice President of Finance and Treasurer since August 2009. Mr. Canaday was Vice President and Controller from June 2008 until July 2009 and was Interim Chief Financial Officer from June 2008 until August 2008. Mr. Canaday served as Controller from February 2007 to July 2009, as Treasurer from December 2004 to February 2007 and as Senior Financial Analyst from November 2003 until December 2004. Mr. Canaday has worked in the oil and natural gas industry since 1998 in various finance functions at Chevron and in public accounting. Mr. Canaday is also an Assistant Secretary.

DAVIS O. O'CONNOR, 57, has been the Vice President, General Counsel, and Secretary since October 2010. He previously served as a partner and an associate with the Denver law firm of Holland and Hart LLP since 1979 where he practiced in the areas of domestic and international business transactions including mergers, acquisitions, divestitures, joint ventures and related transactions, primarily in the oil and natural gas industry.

JAMIE L. WHEAT, 41, has held the position of Principal Accounting Officer since March 2010, and Controller since August 2009. Ms. Wheat was the Accounting Manager from August 2008 until August 2009. Prior to joining the Company, Ms. Wheat was a Senior Manager in the assurance practice group of KPMG, where she worked from 2001 to 2008.

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PART II

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

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

Our Class A Common Stock is listed on the New York Stock Exchange under the symbol BRY. The Class B Stock is not publicly traded. The market data and dividends for 2011 and 2010 are shown below:

	2011			2010		
	Price Range		Dividends	Price Range		Dividends
	High	Low	Per Share	High	Low	Per Share
First Quarter	$52.32	$42.61	$.075	$31.27	$25.62	$.075
Second Quarter	53.76	44.13	.075	34.30	25.57	.075
Third Quarter	61.17	36.53	.080	32.23	24.30	.075
Fourth Quarter	47.92	30.62	.080	44.80	30.65	.075
Total Dividends Paid			$.310			$.300

There were 489 holders of record of our Class A Common Stock and one holder of record of our Class B Stock as of February 14, 2012.

Dividends

Our regular quarterly dividend is payable in March, June, September and December. In the third quarter of 2011, the regular quarterly dividend was increased from $0.075 per share to $0.08 per share, resulting in a regular annual dividend of $0.31 per share for 2011.

Since our formation in 1985 through December 31, 2011, we have paid dividends on our Common Stock for 89 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 (i) our credit facility to the greater of $35 million or 75% of net earnings for any four quarter period, and (ii) the indentures governing our senior and subordinated notes to up to $0.36 per share annually (but in no event in excess of $20 million annually) in the event that we are not in default under such indentures, and up to $10 million in the event we are in a non-payment default under such indentures.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance
Equity compensation plans approved by security holders (1)	1,520,690	$30.32	886,893
	—	—	—

Equity compensation plans not
approved by security holders

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(1) Excludes 400,570 shares of restricted stock units for which the vesting period has not lapsed.

Issuer Purchases of Equity Securities

None.

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Performance Graph

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

Total returns assume $100 invested on December 31, 2006 in shares of Berry Petroleum Company, the Russell 2000, the Standard & Poors 500 Index and a Peer Group, assuming reinvestment of dividends for each measurement period. The information shown is historical and is not necessarily indicative of future performance. The 14 companies which make up the "Peer Group" are as follows: Bill Barrett Corp., Cabot Oil & Gas Corp., Cimarex Energy Co., Comstock Resources Inc., Denbury Resources Inc., Forest Oil Corp., Penn Virginia Corp., Plains Exploration & Production Co., Quicksilver Resources Inc., Sandridge Energy Inc., SM Energy Co., Stone Energy Corp., Swift Energy Co. and Whiting Petroleum Corp.

	12/06	12/07	12/08	12/09	12/10	12/11
Berry Petroleum Company	100.00	144.57	24.93	98.18	148.59	143.88
S&P 500	100.00	105.49	66.46	84.05	96.71	98.75
Russell 2000	100.00	98.43	65.18	82.89	105.14	100.75
Peer Group	100.00	138.37	60.49	91.69	116.56	106.44

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Item 6. Selected Financial Data

The following table sets forth certain financial information and is qualified in its entirety by reference to the historical financial statements and notes thereto included in Item 8. Financial Statements and Supplementary Data. The financial information at December 31, 2011 and 2010 and for the years ended December 31, 2011, 2010 and 2009 was derived from our audited financial statements and the accompanying notes to those financial statements included in Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K. The financial information at December 31, 2009, 2008 and 2007 and for the years ended December 31, 2008 and 2007 was derived from unaudited financial data not included in the report.

	Year Ended December 31,				
(in thousands, except per share, production, and per BOE data)	2011	2010	2009	2008	2007
Statements of Operations Data:					
Operating Revenues (continuing operations)	$919,558	$676,510	$559,403	$746,632	$478,099
Net (loss) earnings from continuing operations	(228,063)	82,524	47,224	120,577	120,666
Basic net (loss) earnings per share from continuing operations	(4.21)	1.54	1.03	2.67	2.71
Diluted net (loss) earnings per share from continuing operations	$(4.21)	$1.52	$1.02	$2.64	$2.67
Production Data (continuing operations):					
Oil production (MBOE)	9,041	7,925	7,186	7,441	7,210
Natural gas production (MMcf)	23,907	23,988	20,982	18,323	8,817
Operating Data (continuing operations) (per BOE):					
Average sales price(1)	$71.59	$53.69	$41.23	$73.64	$52.30
Average operating costs—oil and natural gas production	18.23	15.95	14.66	17.99	15.09
Production taxes	2.58	1.93	1.70	2.56	1.69
G&A	4.74	4.43	4.61	5.17	4.57
DD&A—oil and natural gas production	$16.42	$15.05	$13.10	$11.97	$9.55
Balance Sheet and Other Data (at period end):					
Total assets	$2,734,952	$2,838,616	$2,240,135	$2,542,383	1,452,106
Long-term debt	1,380,192	1,108,965	1,008,544	1,131,800	445,000
Dividends per share	$0.31	$0.30	$0.30	0.30	$0.30
Cash Flow Data:					
Cash flow from operations	$455,899	$367,237	$212,576	409,569	$238,879
Exploration and development of oil and natural gas properties	527,112	310,139	134,946	397,601	285,267
Property acquisitions	$158,090	334,409	$13,497	667,996	$56,247

(1) Excludes all effects of derivatives. See Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information regarding the effect of derivatives on our average realized price.

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

The following discussion and analysis should be read in conjunction with Item 6. 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 Annual Report on Form 10-K.

Overview

Our results are directly related to the realized prices of oil, natural gas and electricity sold, the type and volume of oil and natural gas produced and electricity generated and the results of development, exploitation, acquisition and hedging activities. The realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices are predominantly influenced by global supply and demand. Beginning in the second half of 2009 and through 2011, oil prices rebounded from the lows seen during the recent recession and financial crises. Natural gas prices have fallen significantly since their peak in the third quarter of 2008 and have remained low through 2011. The aggregate amount of oil and natural gas we produce may fluctuate based on the success of development and exploitation of oil and natural gas reserves pursuant to current reservoir management.

The principal influences on our operating costs include the cost of natural gas used in our steam operations and electrical generation, production rates, labor and equipment costs, maintenance expenses and production taxes. We have historically been a net producer of natural gas and have benefited operationally when natural gas prices increase. Our production of natural gas has, in the past, provided a form of natural hedge against rising steam costs. As our natural gas production continues to decrease and our use of natural gas for steaming operations increase, we may become a net consumer of natural gas and would no longer benefit operationally when natural gas prices increase.

Diatomite

We received a new full-field development approval in late July 2011 from the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR) with respect to our Diatomite assets. The approval contained operating requirements that were significantly more stringent than similar specifications contained in prior approvals from DOGGR. The development of our Diatomite assets and associated production growth were on track in 2011, but the implementation of these newer operating requirements negatively impacted the pace of drilling and steam injection, and this impact has continued into 2012. We are working constructively with DOGGR on the operating specifications for our Diatomite assets to enable an increase in the pace of our development.

On February 24, 2012, we received revisions to the July 2011 project approval letter, which, among other things, allow us to conduct mechanical integrity testing at least once every five years, rather than annually as provided in the original project approval letter. In addition, we are longer required to cease cyclic steaming operations on wells located within 150 feet of a failed well bore, subject to demonstrating to DOGGR that steam injection into such surrounding wells will be confined to the Diatomite zone. Our estimates of well performance and ultimate recovery for the asset remain unchanged. We are currently assessing the impact of the revised project approval letter on the development and operations of our Diatomite properties.

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Notable Items in 2011

- Generated an operating margin of $44.87 per BOE and discretionary cash flow of $461.9 million(1)
- Increased oil production 14% and total production 9% to 35,687 BOE/D
- Increased our pre-tax PV10 value by 50% to $5.7 billion as a result of strong oil pricing, favorable heavy oil differentials and a 12% BOE increase in oil reserves(1)
- Increased oil reserves to 68% of total proved reserves
- Acquired approximately 22,000 additional net acres in the Permian for $150.9 million, bringing our total Permian position to 42,000 net acres
- Drilled 69 net wells in the Permian and exited 2011 at 5,700 BOE/D
- Drilled 45 net wells in Uinta, including nine Uteland Butte horizontal wells
- Sold our California heavy oil at a $7.81 average premium to WTI
- Increased Diatomite production by 16% to 3,154 BOE/D
- Increased our borrowing base under our credit facility from $875 million to $1.4 billion and lender commitments from $875 million to $1.2 billion
- Repurchased $94.7 million aggregate principal amount of our 10.25% senior notes due 2014 (2014 Notes)
- Recorded an impairment of $625.0 million on our E. Texas properties due to low natural gas prices

Expectations for 2012

- Anticipating average production between 38,000 BOE/D and 39,000 BOE/D, a 6% to 9% increase over 2011, overcoming an expected 22% decrease in natural gas production
- Planning to invest our 2012 capital budget in our oil assets, targeting oil production growth of approximately 20% to over 75% of total production
- Expecting to drill approximately 100 Permian wells, increasing average production to approximately 7,500 BOE/D
- Expecting to drill over 70 Utah wells, including Green River/Wasatch commingled wells and Uteland Butte horizontal wells, increasing average production to approximately 6,000 BOE/D
- Continuing to work with DOGGR on Diatomite operating specifications to increase the pace of development
- Continuing to evaluate acquisition opportunities that fit into our core areas of operation

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(1) Discretionary cash flow, operating margin and pre-tax PV10 are non-GAAP measures and reference should be made to "Reconciliation of Non-GAAP Measures" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations for further explanation as well as reconciliations to the most directly comparable GAAP measures.

2012 Capital Budget

We expect our 2012 capital budget, excluding acquisitions to range between $600 million and $650 million assuming an average commodity price of $90 WTI, which we expect to fund with net cash provided by our operating activities. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we may adjust our capital budget accordingly or adjust borrowings under our credit facility, as needed.

Results of Operations

We experienced a net loss of $228.1 million, or $4.21 per diluted share, for the year ended December 31, 2011. The net loss included a charge of $385.3 million related to the impairment of our E. Texas natural gas properties, a charge of $38.0 million resulting from amortization of accumulated other comprehensive loss (AOCL) related to discontinuing hedge accounting, a charge of $9.2 million associated with repurchasing $94.7 million principal amount of our 2014 Notes and a charge of $2.6 million related to the impairment of our drilling rigs, partially offset by a gain of $56.0 million resulting from non-cash changes in fair value of derivative instruments and a gain of $2.6 million related to a retroactive payment adjustment for capacity from one of our electricity customers, in each case net of income taxes. Net cash provided by operating activities was $455.9 million and capital expenditures, excluding capitalized interest and property acquisitions, totaled $527.1 million. We drilled 367 net wells during 2011 and achieved average daily production of 35,687 BOE/D in 2011, an increase of 9% from 2010.

We experienced a net loss of $414.7 million, or $7.62 per diluted share, for the fourth quarter of 2011. The net loss included a charge of $387.6 million related to the impairment of our E. Texas natural gas properties, a charge of $58.9 million resulting from non-cash changes in the fair value of derivative instruments, a charge of $9.6 million resulting from amortization of AOCL related to discontinuing hedge accounting and a charge of $2.6 million related to the impairment of our drilling rigs, partially offset by a gain of $2.6 million related to a retroactive payment adjustment for capacity from one of our electricity customers, in each case net of income taxes. Net cash provided by operating activities was $84.0 million and capital expenditures, excluding capitalized interest and property acquisitions, totaled $103.0 million. We drilled 94 net wells during the quarter and achieved average daily production of 35,790 BOE/D, a decrease of 3% from the third quarter of 2011, primarily due to more stringent operating regulations with respect to our Diatomite assets, imposed curtailments by our third-party processors in the Permian and the natural production declines at our Piceance and E. Texas properties.

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Operating Data

The following table sets forth selected operating data for the years ended:

	December 31, 2011	%	December 31, 2010	%	December 31, 2009	%
Oil and Natural Gas						
Heavy oil production (BOE/D)	17,397	49	17,124	52	16,842	56
Light oil production (BOE/D)	7,374	21	4,589	14	2,846	10
Total oil production (BOE/D)	24,771	70	21,713	66	19,688	66
Natural gas production (Mcf/D)	65,498	30	65,720	34	62,074	34
Total production (BOE/D)(1)	35,687	100	32,666	100	30,034	100
Less DJ production	—		—		765	
Production—continuing operations (BOE/D)(1)	35,687		32,666		29,269	
Oil and natural gas, per BOE, from continuing operations:						
Average realized sales price	$66.91		$52.14		$46.72	
Average sales price including cash derivative settlements	$65.68		$53.84		$46.02	
Oil, per BOE, from continuing operations:						
Average WTI price	$95.11		$79.59		$62.09	
Price sensitive royalties(2)	(3.60	)	(3.06	)	(2.04	)
Quality differential and other(3)	0.84		(8.92	)	(9.08	)
Oil derivatives non-cash amortization(4)	(6.77	)	(2.59	)	—	
Oil derivatives cash settlements(5)	—		—		7.47	
Correction to royalties payable(6)	—		—		(0.24	)
Oil revenue	$85.58		$65.02		$58.20	
Oil derivatives non-cash amortization(4)	6.77		2.59		—	
Oil derivatives cash settlements(7)	(9.72	)	(0.90	)	(0.92	)
Average realized oil price	$82.63		$66.71		$57.28	
Natural gas, per Mcf, from continuing operations:						
Average Henry Hub price per MMBtu	$4.04		$4.39		$4.00	
Conversion to Mcf	0.28		0.22		0.20	
Natural gas derivatives non-cash amortization(4)	0.01		0.08		—	
Natural gas derivative cash settlements(5)	—		—		0.23	
Location, quality differentials and other	(0.23	)	(0.24	)	(0.59	)
Natural gas revenue	$4.10		$4.45		$3.84	
Natural gas derivatives non-cash amortization(4)	(0.01	)	(0.08	)	—	
Natural gas derivative cash settlements(7)	0.46		0.37		(0.04	)
Average realized natural gas price	$4.55		$4.74		$3.80	

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.
(2) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above a base price which was $17.09 per barrel in 2011 as long as we maintain a

minimum steam injection level. We met the steam injection level in 2011 and expect to meet the requirement going forward. This base price escalates at 2% annually and will be $17.43 per barrel in 2012.

(3) In California, the differential at December 31, 2011, was $2.48 and ranged from a low of ($6.43) to a high of $22.77 per barrel during the year. In Utah, the differential at December 31, 2011,was ($13.75) and averaged ($14.10) during 2011.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in sales of oil and natural gas.

(5) Includes cash settlements on hedges prior to January 1, 2010, for which we had elected hedge accounting. Recorded in sales of oil and natural gas.

(6) 2009 includes a correction to one of our royalties payable in the amount of $1.9 million, which resulted in decreasing our sales of oil and natural gas and increasing our royalties payable.

(7) Includes cash settlements on derivative instruments recorded in realized and unrealized (gain) loss on derivatives, net.

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The following table sets forth selected operating data for the three months ended:

	December 31, 2011	%	December 31, 2010	%	September 30, 2011	%
Oil and Natural Gas						
Heavy oil production (BOE/D)	17,497	49	16,548	48	18,173	49
Light oil production (BOE/D)	8,166	23	6,131	18	7,918	22
Total oil production (BOE/D)	25,663	72	22,679	66	26,091	71
Natural gas production (Mcf/D)	60,759	28	70,828	34	64,950	29
Total production—continuing operations (BOE/D)(1)	35,790	100	34,484	100	36,916	100
Oil and natural gas, per BOE, from continuing operations:						
Average realized sales price	$69.29		$53.55		$66.74	
Average sales price including cash derivative settlements	$68.80		$53.75		$67.62	
Oil, per BOE, from continuing operations:						
Average WTI price	$94.06		$85.20		$89.48	
Price sensitive royalties(2)	(3.63)		(3.37)		(3.37)	
Quality differential and other(3)	4.75		(9.16)		4.45	
Oil derivatives non-cash amortization(4)	(6.76)		(3.22)		(6.56)	
Oil revenue	$88.42		$69.45		$84.00	
Oil derivatives non-cash amortization(4)	6.76		3.22		6.56	
Oil derivative cash settlements(5)	(8.89)		(4.35)		(6.32)	
Average realized oil price	$86.29		$68.32		$84.24	
Natural gas, per Mcf, from continuing operations:						
Average Henry Hub price per MMBtu	$3.54		$3.80		$4.20	
Conversion to Mcf	0.21		0.19		0.21	
Natural gas derivatives non-cash amortization(4)	—		0.05		0.02	
Location, quality differentials and other	(0.24)		(0.14)		(0.18)	
Natural gas revenue	$3.51		$3.90		$4.25	
Natural gas derivatives non-cash amortization(4)	—		(0.05)		(0.02)	
Natural gas derivative cash settlements(5)	0.61		0.50		0.42	
Average realized natural gas price	$4.12		$4.35		$4.65	

(1) Oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of oil.

(2) Our Formax property in S. Midway is subject to a price-sensitive royalty burden. The royalty is 53% of the amount of the heavy oil posted price above a base price which was $17.09 per barrel in 2011 as long as we maintain a minimum steam injection level. We met the steam injection level in 2011 and expect to meet the requirement going forward. This base price escalates at 2% annually and will be $17.43 per barrel in 2012.

(3) In California, the differential at December 31, 2011, was $2.48 and ranged from a low of $2.48 to a high of $22.43 per barrel during the fourth quarter of 2011. In Utah, the differential at December 31, 2011, was ($13.75) and averaged ($13.13) during the fourth quarter of 2011.

(4) Non-cash amortization of AOCL resulting from discontinuing hedge accounting effective January 1, 2010. Recorded in sales of oil and natural gas.

(5) Includes cash settlements on derivatives recorded in realized and unrealized (gain) loss on derivatives, net.

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The following table reflects our results from continuing operations (in thousands, except per share data):

	Twelve months ended,			Three months ended,		
	December 31, 2011	December 31, 2010	December 31, 2009	December 31, 2011	December 31, 2010	September 30, 2011
Sales of oil	$ 772,685	$ 512,699	$ 419,991	$ 207,689	$ 143,246	$ 199,930
Sales of natural gas	98,088	106,909	80,541	19,609	25,359	25,395
Sales of oil and natural gas	$ 870,773	$ 619,608	$ 500,532	$ 227,298	$ 168,605	$ 225,325
Sales of electricity	34,953	34,740	36,065	10,750	7,427	9,826
Natural gas marketing	13,832	22,162	22,806	2,550	3,968	3,612
Settlement on Flying J bankruptcy claim	—	21,992	—	—	—	—
Gain (loss) on sale of assets	—	—	826	—	—	—
Interest and other income, net	1,784	3,300	1,810	390	980	463
Total revenues and other income	$ 921,342	$ 701,802	$ 562,039	$ 240,988	$ 180,980	$ 239,226
Net (loss) earnings from continuing operations	$ (228,063)	$ 82,524	$ 47,224	$ (414,733)	$ (21,145)	$ 134,001
Diluted net (loss) earnings per share from continuing operations	$ (4.21)	$ 1.52	$ 1.02	$ (7.62)	$ (0.40)	$ 2.42

Sales of Oil and Natural Gas

Sales of oil and natural gas increased $251.2 million, or 41%, to $870.8 million in 2011 from $619.6 million in 2010. The increase was primarily due to a 10% increase in sales volumes and an increase in the average sales price to $66.91 per BOE in 2011 from $52.14 per BOE in 2010, which includes an increase in the non-cash amortization of AOCL related to discontinuing hedge accounting to $60.9 million, or $4.68 per BOE, for 2011, compared to $18.4 million, or $1.55 per BOE, for 2010. Sales of oil and natural gas increased $119.1 million, or 24%, to $619.6 million for 2010 from $500.5 million for 2009. The increase was primarily due to a 11% increase in sales volumes and an increase in the average realized sales price to $52.14 per BOE in 2010 from $46.72 per BOE in 2009, which includes an increase in the non-cash amortization of AOCL related to discontinuing hedge accounting to $18.4 million, or $1.55 per BOE, for 2010. There was no non-cash amortization of AOCL related to discontinuing hedge accounting in 2009.

Total production from continuing operations in 2011 increased 3,021 BOE/D, or 9%, to 35,687 BOE/D, from 32,666 BOE/D in 2010, primarily due to development activities and the contribution of our acquisitions in the Permian, and partially offset by more stringent operating regulations with respect to our Diatomite assets, imposed curtailments by our third-party processors in the Permian and planned production declines at our Piceance and E. Texas properties. In 2011, we drilled a total of 367 net wells compared to 232 net wells in 2010. Total production from continuing operations increased 3,397 BOE/D, or 12%, to 32,666 BOE/D in 2010 from 29,269 BOE/D in 2009, primarily due to our development activities and the contribution of our acquisitions in the Permian. In 2010, we drilled a total of 232 net wells compared to 132 net wells in 2009.

Sales of Electricity

Sales of electricity increased $0.2 million, or 1%, to $34.9 million in 2011 from $34.7 million in 2010, primarily due to the refund of $4.1 million received in December 2011 from one of our electricity customers associated with a retroactive payment adjustment for capacity. As a result of the Global Settlement, we received retroactive payments for firm capacity that had been originally paid at "as available" capacity rates, and the payment received in December 2011 represents the difference in rates over the disputed period. This increase was offset by a 6% decrease in the average sales price of electricity and a 6% decrease in electric power sold associated with an increase in cogeneration unit downtime in 2011. Operating costs—electricity generation decreased $5.6 million, or 18%, to $25.7 million in 2011 from $31.3 million in 2010 primarily due to a 6% decrease in fuel gas cost and a 6% decrease in electric power produced related to increased cogeneration unit downtime in 2011.

Sales of electricity decreased $1.3 million, or 4%, to $34.7 million in 2010 from $36.1 million in 2009, primarily due to a $1.7 million adjustment received in 2009 relating to a retroactive revision to payments received from PG&E. Operating cost—electricity generation remained relatively unchanged in 2010 compared to 2009.

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	Year Ended December 31,		
	2011	2010	2009
Electricity			
Sales of electricity (in thousands)	$34,953	$34,740	$36,065
Operating costs (in thousands)	$25,690	$31,295	$31,400
Electric power produced—MWh/D	1,968	2,088	2,098
Electric power sold—MWh/D	1,806	1,925	1,907
Average sales price/MWh	$47.00	$50.06	$60.99
Fuel gas cost/MMBtu (including transportation)	$4.20	$4.49	$3.86

We purchased approximately 25,000 MMBtu/D, 27,000 MMBtu/D and 27,000 MMBtu/D of natural gas as fuel in our cogeneration facilities for the years ended December 31, 2011, 2010 and 2009, respectively. We purchase and transport, on average, 12,000 MMBtu/D on the Kern River Pipeline under our firm transportation contract

Natural Gas Marketing

We have long-term firm transportation contracts on the Rockies Express, Wyoming Interstate Company (WIC), and Ruby pipelines, each with total average capacities of 35,000 MMBtu/D. Demand charges for our capacity are reflected in operating costs-oil and natural gas production in our Statements of Operations. Our current production is insufficient to fully utilize this capacity. To optimize our remaining capacity, we purchase third-party natural gas at the market rate in our producing areas utilizing FERC-approved asset management agreements. Sales and purchases of third-party natural gas are recorded under natural gas marketing in the revenues and expenses section of the Statement of Operations, respectively.

The pre-tax net of our natural gas marketing revenue and our natural gas marketing expense for the years ended December 31, 2011, 2010 and 2009 was $0.8 million, $2.3 million and $1.6 million, respectively.

Realized and Unrealized (Gain) Loss on Derivatives, Net

Realized and unrealized (gain) loss on derivatives, net is primarily related to derivative instruments for which we did not elect hedge accounting or derivatives which did not qualify for hedge accounting either at the inception of the derivative instrument or where hedge accounting was discontinued during the term of the derivative instrument. When the criteria for hedge accounting is not met or when hedge accounting is not elected, realized gains and losses (e.g., cash settlements) and unrealized gains and losses (e.g., non-cash changes in fair value) are recorded in realized and unrealized (gain) loss on derivatives, net in our Statements of Operations. Conversely, cash settlements of derivative instruments accounted for under hedge accounting are recorded as additions to or reductions of sales of oil and natural gas or interest expense, while changes in fair value of derivative instruments are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Realized and unrealized (gain) loss on derivatives, net also includes any hedge ineffectiveness on cash flow hedges accounted for under hedge accounting.

During 2009, we entered into commodity derivative instruments for which we did not elect hedge accounting. In addition, effective January 1, 2010, we elected to discontinue hedge accounting for all of our commodity and interest rate derivative instruments for which we had previously elected hedge accounting, and have elected to discontinue all hedge accounting prospectively. Accordingly, beginning January 1, 2010, changes in the fair value of derivative instruments are recognized immediately in net earnings in our Statements of Operations. Cash flows from operating activities are impacted to the extent that actual cash settlements under our derivative instruments result in making or receiving a payment to or from a counterparty, and such cash settlement gains and losses are recorded under the caption realized and unrealized (gain) loss on derivatives, net in our Statements of Operations. See Notes 8 and 9 to the Financial Statements. Also, See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further details concerning our hedging activities.

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The following table sets forth the cash settlements and non-cash fair value gains and losses recorded in realized and unrealized (gain) loss on derivatives, net:

	Year Ended December 31,		
	2011	2010	2009
	(in thousands)		
Cash receipts payments (receipts):			
Commodity derivatives—oil	$87,747	$7,078	$6,671
Commodity derivatives—natural gas	(10,806)	(8,889)	888
Financial derivatives—interest(1)	—	17,499	—
Total cash payments	$76,941	$15,688	$7,559
Non-cash fair value (gain) loss:			
Commodity derivatives—oil	$(89,478)	$37,440	$—
Commodity derivatives—natural gas	(1,371)	(12,424)	(355)
Financial derivatives—interest(1)	—	(8,857)	—
Total fair value (gain) loss	$(90,849)	$16,159	$(355)
Realized and unrealized (gain) loss on derivatives, net	$(13,908)	$31,847	$7,204

(1) In the fourth quarter of 2010, we terminated certain interest rate derivative instruments for which we had previously elected hedge accounting. The termination resulted in a cash settlement of $10.8 million, offset by a fair value gain of $8.9 million.

During the year ended December 31, 2009, we recorded $0.6 million under the caption realized and unrealized (gain) loss on derivatives, net as a result of ineffectiveness on cash flow hedges.

Settlement of Flying J Bankruptcy

On July 6, 2010, the Joint Plan of Reorganization of Flying J, Inc., Big West of California, LLC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United State Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of our claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, we and Flying J agreed that the total amount owed to us by Flying J for the purchases of our California production and other damages was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010.

Oil and Natural Gas Operating and Other Expenses

The following table presents information about our oil and natural gas operating and other expenses from continuing operations for each of the years ended December 31:

	Amount per BOE			Amount (in thousands)		
	2011	2010	2009	2011	2010	2009
Operating costs—oil and natural gas production	$18.23	$15.95	$14.66	$237,476	$190,218	$156,612
Production taxes	2.58	1.93	1.70	33,617	22,999	18,144
DD&A—oil and natural gas production	16.42	15.05	13.10	213,859	179,432	139,919
G&A	4.74	4.43	4.61	61,727	52,846	49,237
Interest	5.59	5.58	4.67	72,807	66,541	49,923

Total	$47.56	$42.94	$38.74	$619,486	$512,036	$413,835

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- Operating costs—oil and natural gas production were $237.5 million in 2011, an increase of $47.3 million, or 25%, from $190.2 million in 2010. On a per BOE basis, operating costs—oil and natural gas production were $18.23 per BOE in 2011, an increase of $2.28 per BOE, or 14%, from $15.95 per BOE in 2010. The increase primarily results from higher steam costs resulting from higher volumes of injected steam, partially offset by a decrease in natural gas fuel cost and increases in water hauling and disposal costs, well maintenance and workover costs, contract labor costs and transportation costs. Operating costs—oil and natural gas production were $190.2 million in 2010, an increase of $33.6 million, or 21%, compared to $156.6 million in 2009. On a per BOE basis, operating costs—oil and natural gas production were $15.95 per BOE in 2010, an increase of $1.29 per BOE, or 9%, from $14.66 per BOE in 2009. The increase was primarily due to higher steam costs resulting from higher volumes of injected steam and higher natural gas fuel costs, higher expenditures for well workovers and higher compression, gathering, and dehydration costs.

Firm transportation costs totaled $21.4 million, $16.2 million and $16.1 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increase in firm transportation costs in 2011 was due primarily to the commencement of Ruby Pipeline operations in July 2011.

The following table presents steam information:

	Year Ended December 31,		
	2011	2010	2009
Average volume of steam injected (Bbl/D)	133,404	116,956	109,153
Fuel gas cost/MMBtu (including transportation)	$4.20	$4.49	$3.86
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	44,235	36,020	30,462

- Production taxes were $33.6 million in 2011, an increase of $10.6 million, or 46%, from $23.0 million in 2010. On a per BOE basis, production taxes were $2.58 per BOE in 2011, an increase of $0.65, or 34%, from $1.93 per BOE in 2010. The increase in production taxes was primarily due to an increase in the assessed ad valorem values attributed to our California properties and an increase in the number of wells outside California, where property taxes are based largely on assessed value per well. Additionally, our severance taxes increased in 2011, largely due to increased commodity prices. Production taxes were $23.0 million in 2010, an increase of $4.9 million, or 27%, from $18.1 million in 2009. On a per BOE basis, production taxes were $1.93 per BOE in 2010, an increase of $0.23 per BOE, or 14%, from $1.70 per BOE in 2009. The increase in production taxes was primarily due to an increase in the assessed ad valorem values attributed to our California properties. In addition, our West Texas and Utah properties contributed to a higher cost per BOE due to severance taxes tied to the field sales price of the commodity.

- Depreciation, depletion and amortization—oil and natural gas production (DD&A—oil and natural gas production) was $213.9 million in 2011, an increase of $34.4 million, or 19%, from $179.4 million in 2010. On a per BOE basis, DD&A—oil and natural gas production was $16.42 per BOE in 2011, an increase of $1.37 per BOE, or 9%, from $15.05 per BOE in 2010. The increase in DD&A—oil and natural gas production per BOE is primarily due to an overall shift in production volumes to our assets outside of California, which have higher drilling and leasehold acquisition costs than our California properties. In 2011, 49% of our production volumes were heavy oil produced in California, compared to 52% of our production volumes in 2010. DD&A—oil and natural gas production was $179.4 million in 2010, an increase of $39.5 million, or 28%, from $139.9 million in 2009. On a per BOE basis, DD&A—oil and natural gas production was $15.05 per BOE in 2010, an increase of $1.95, or 15%, from $13.10 per BOE in 2009. The increase in DD&A—oil and natural gas production per BOE was primarily due to the contribution of our development properties with higher drilling and leasehold acquisition costs than our California properties, including our recent acquisitions in the Permian and a shift in production volumes to assets outside of California.

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General and administrative expense (G&A) was $61.7 million in 2011, an increase of $8.9 million, or 17%, from $52.8 million in 2010. On a per BOE basis, G&A was $4.74 per BOE in 2011, an increase of $0.31 per BOE, or 7%, from $4.43 per BOE in 2010. The increase is due in part to higher employee salary and benefit costs. As of December 31, 2011, we had 317 full-time employees compared to 270 as of December 31, 2010. The increase in employees was primarily due to our acquisitions in the Permian and additional personnel required for our growing capital program and production levels. Additionally, G&A increased due to higher consulting costs directly attributable to our efforts to comply with new regulations in California, as well as our growing capital program and production levels. G&A was $52.8 million in 2010, an increase of $3.6 million, or 7%, from $49.2 million in 2009. On a per BOE basis, G&A was $4.43 per BOE in 2010, a decreased of $0.18 per BOE, or 4%, from $4.61 per BOE in 2009. The increase was largely

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due to increases in employee compensation, including bonuses, related to increased employees in the Permian and to support increasing production. The decrease in G&A on a per BOE basis was due to increased production.

Interest was $72.8 million in 2011, an increase of $6.3 million, or 9%, from $66.5 million in 2010. The increase in interest is a result the issuance of our 6.75% senior notes due 2020 (2020 Notes) in November 2010 and an increase in the average amount of borrowings outstanding under our credit facility. These increases were partially offset by a decrease in non-cash derivative losses of $7.5 million related to the de-designated interest rate hedges reclassified from AOCL into interest expense and a decrease in interest payments related to the repurchase of $94.7 million aggregate principal amount of our 2014 Notes in September and October of 2011. Interest was $66.5 million in 2010, an increase of $16.6 million, or 33%, compared to $49.9 million in 2009. Interest in 2010 included non-cash derivative losses of $8.3 million related to the de-designated interest rate hedges reclassified from AOCL into interest . In addition, interest increased due to the issuances of our 2014 Notes in May and August of 2009 and our 2020 Notes in November 2010, partially offset by a decrease in the average amount of borrowings outstanding under our credit facility.

Extinguishment of Debt. We recorded debt extinguishment costs of $15.5 million, $0.6 million and $10.8 million in 2011, 2010 and 2009, respectively. In 2011, we wrote off $15.0 million in conjunction with the repurchase of $94.7 million aggregate principal amount of our 2014 Notes, consisting of $11.5 million in premium paid over par and $3.5 million in write-offs of net discount and deferred financing costs. We also wrote off $0.5 million associated with one lender that did not renew its commitment under our credit facility in October 2011. In 2010, we wrote off $0.6 million associated with borrowing base changes under our credit facility. In 2009, we wrote off costs associated with borrowing base changes under our credit facility and fees associated with the extinguishment of our second lien term loan.

Transaction Costs on Acquisitions. In 2010, we incurred $2.6 million of acquisition related expenses for the acquisition of certain properties in the Permian. See Note 2 to the Financial Statements.

Impairment of Oil and Natural Gas Properties. We recorded non-cash impairments of oil and natural gas properties in continuing operations of $625.6 million, $0.0 million, and $1.0 million, in 2011, 2010 and 2009, respectively.

In the fourth quarter of 2011, we recorded a non-cash impairment of $625.0 million related our E. Texas natural gas properties. The impairment was due to decreases in natural gas prices and, as a result, changes in our development plans. In the fourth quarter of 2011, the NYMEX HH five-year future strip (the average of the settlement prices of the next 60 months' futures contracts) decreased approximately 15%. The assets were written down to their estimated fair value. Further, in 2011, 2010 and 2009, we recorded non-cash impairments in continuing operations of $0.6 million, $0 million and $1.0 million related to the expiration of acreage primarily in the Uinta. See Notes 9 and 11 to the Financial Statements.

In 2009, we recorded a non-cash impairment in discontinued operations of $9.6 million related to the sale of our DJ assets. See Note 2 to the Financial Statements.

Dry Hole, Abandonment, Impairment and Exploration. We recorded dry hole, abandonment and impairment charges of $5.2 million, $1.5 million and $4.2 million in 2011, 2010 and 2009, respectively. In 2011, we recorded a $4.3 million impairment charge related to the write-down of three rigs to their fair value. In 2010, we recorded dry hole expense due to a mechanical failure encountered on one well in the Piceance. In 2009, we recorded a $4.2 million impairment charge related to the write-down of a rig to its fair value. See Notes 9 and 11 to the Financial Statements.

We incurred exploration costs in 2011, 2010 and 2009, of $0.1 million, $0.8 million and $0.2 million, respectively. These costs consist primarily of geological and geophysical costs.

Bad Debt (Recovery) Expense. On July 6, 2010, the Joint Plan of Reorganization of Flying J was confirmed under Chapter 11 of the United States Bankruptcy Code. Additionally, the United States Bankruptcy Court approved and confirmed the Stipulation, pursuant to which Flying J agreed that the total amount owed to us by Flying J was $60.5 million and, as a result, we received $60.5 million in cash on July 23, 2010. In 2010, we recorded a settlement of our Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

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Income Tax (Benefit) Expense. Our effective income tax rates for the years ended December 31, 2011, 2010, and 2009 were 38%, 40% and 30%, respectively. In 2011, we recorded an income tax benefit due to a pre-tax loss as a result of the impairment of our E. Texas natural gas properties. In 2009, the effective income tax rate was impacted by reduced state rates and a decrease in our liability related to uncertain income tax positions. Our estimated annual effective income tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences (i.e., differences between book earnings and taxable income that are not expected to reverse in future periods). See Note 5 to the Financial Statements.

Estimated 2012 Oil and Natural Gas Operating, G&A and Interest Expense. We estimate our 2012 production volume will range between 38,000 BOE/D and 39,000 BOE/D. Based on WTI of $90.00 and NYMEX HH of $3.00 MMBtu, we expect our oil and natural gas operating and other expenses to be within the following ranges:

	Amount per BOE		
	Anticipated range in 2012	2011	2010
Operating costs—oil and natural gas production	$17.00 - 19.50	$ 18.23	$ 15.95
Production taxes	2.50 - 3.25	2.58	1.93
DD&A	15.00 - 18.00	16.42	15.05
G&A	4.25 - 5.50	4.74	4.43
Interest expense	5.50 - 6.25	5.59	5.58
Total	$44.25 - 52.50	$47.56	$42.94

Financial Condition, Liquidity and Capital Resources

Our development, exploitation and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and borrowings under our credit facility as our primary sources of liquidity. The debt and equity capital markets have served as our primary source of financing to fund large acquisitions and other transactions. 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 monetization transactions as a source of financing, as market conditions have permitted. In April 2009, we sold our assets in the DJ for $139.8 million, and in July 2009 we completed the sale of our E. Texas natural gas gathering system for $18.4 million. As we pursue profitable reserves and production growth, we continually monitor the capital resources, including the issuance of equity and debt securities, available to us to meet our future financial obligations, planned capital expenditure activity and liquidity.

At December 31, 2011, we had a working capital deficit of approximately $63.5 million. We generally maintain a working capital deficit because we use excess cash to reduce outstanding borrowings under our credit facility. Our working capital fluctuates for various reasons, including changes in the fair value of our commodity derivative instruments.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flows. As of December 31, 2011, we had hedged approximately 70% and 40% of our expected oil production in 2012 and 2013 in the form of swaps and collars. This level of derivatives is expected to provide a measure of certainty of the cash flows that we will receive for a portion of our production in 2012 and 2013. In the future, we may increase or decrease our derivative positions. At December 31, 2011, all of our derivatives counterparties were commercial banks that are parties, or affiliates of parties, to our credit facility. See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further details concerning our hedging activities.

Revolving Credit Facility. Our senior secured revolving credit facility, which matures in May 2016, has a current borrowing base of $1.4 billion, subject to lender commitments. On October 26, 2011, as part of the semi-annual borrowing base redetermination process, we entered into an amendment to the credit facility which, among other things, increased total lender commitments to $1.2 billion. Borrowings under our credit facility bear interest at either (i) LIBOR plus a margin between 1.50% and 2.50% or (ii) the prime rate plus a margin between 0.50% and 1.50%, in each case, based on the amount utilized. The annual commitment fee on the unused portion of the credit facility ranges between 0.35% to 0.50% based on the amount utilized.

As of December 31, 2011, outstanding borrowings under the facility were $531.5 million (excluding $23.2 million of outstanding letters of credit), leaving $645.3 million in borrowing capacity available under the credit facility. The maximum amount available under the credit facility is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of our proved oil and natural gas reserves, in accordance with the lenders' customary procedures and practices. We and the lenders each of a right to one additional redetermination each year.

The credit facility contains certain covenants, which, among other things, require the maintenance of (i) an interest coverage ratio of 2.75 to 1.0 and (ii) a minimum current ratio of 1.0 to 1.0. The facility also contains other customary covenants, subject to certain agreed exceptions, including covenants restricting our ability to, among other things, owe or be liable for indebtedness; create, assume or permit to exist liens; be a party to or be liable on any hedging contract; engage in mergers or consolidations; transfer, lease, exchange, alienate or dispose of our material assets or properties; declare dividends on or redeem or repurchase our capital stock; make any acquisitions of, capital contributions to or other investments in any entity or property; extend credit or make advances or loans; engage in transactions with affiliates; and enter into, create or allow to exist contractual obligations limiting our ability to grant liens on our assets to the lenders under the senior secured revolving credit facility. We are currently in compliance with all financial covenants and have complied with all financial covenants for each of the years ended December 31, 2010 and 2009.

Subject to certain agreed limitations, we granted first priority security interests over substantially all of our assets in favor of the lenders under the senior secured revolving credit facility.

Money Market Line of Credit. Our senior secured uncommitted money market line of credit has a borrowing capacity of up to $40 million for a maximum of 30 days. As of December 31, 2011, there were no borrowings outstanding under the money market line of credit. Amounts borrowed under the money market line of credit bear interest at LIBOR plus a margin of approximately 1.4%. The line of credit is not currently unavailable to us and we do not know when or if the line of credit will be available in the future.

Other Outstanding Indebtedness. As of December 31, 2011, in addition to our credit facility, we had the following long-term debt outstanding:

- $200 million aggregate principal amount of our 8.25% senior subordinated notes due 2016 (2016 Notes);
- $355.3 million aggregate principal amount of our 2014 Notes; and
- $300 million aggregate principal amount of our 2020 Notes.

The indentures governing our senior and subordinated notes contain provisions that limit our ability to incur, assume or guarantee additional indebtedness; issue redeemable stock and preferred stock; pay dividends or distributions or redeem or repurchase capital stock; prepay, redeem or repurchase debt that is junior in right of payment to our senior and subordinated notes; make loans and other types of investments; incur liens; restrict dividends, loans or asset transfers from our subsidiaries; sell or otherwise dispose of assets, including capital stock of subsidiaries; consolidate or merge with or into, or sell substantially all of our assets to, another person; enter into transactions with affiliates;

and enter into new lines of business. Upon specified change in control events, we will be required to make offers to repurchase our senior and subordinated notes at amounts specified in the indentures governing such notes.

From August to October 2011, we repurchased $94.7 million aggregate principal amount of our 2014 Notes for an aggregate purchase price of $108.8 million, including accrued and unpaid interest. These notes were repurchased using available borrowings under our credit facility. We may from time to time seek to repurchase our outstanding notes, including additional 2014 Notes, through open market purchases, privately negotiated transactions or otherwise. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts repurchased may be material.

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Credit Ratings. Our credit risk is evaluated by two independent rating agencies based on publicly available information and information obtained during our ongoing discussions with the rating agencies. Moody's Investor Services and Standard & Poor's Rating Services currently rate our outstanding notes and have assigned us a credit rating. We do not have any provisions that are linked to our credit ratings, nor do we have any credit rating triggers that would accelerate the maturity of amounts due under our currently outstanding debt. However, our ability to raise funds and the costs of any financing activities will be affected by our credit rating at the time any such financing activities are conducted.

Historical Cash Flows. Cash flows provided by operating activities are primarily affected by the price of oil and natural gas, sales volumes and changes in working capital. The increase in net cash provided by operating activities of $88.7 million in 2011 compared to 2010 is primarily due to a 28% increase in average commodity sales prices and a 10% increase in sales volume. The increase in net cash provided by operating activities of $154.7 million in 2010 compared to 2009 is primarily due to a 12% increase in average commodity sales prices and a 11% increase in sales volume.

Cash flows used by investing activities are primarily comprised of development, exploitation and acquisition of oil and natural gas properties net of dispositions of oil and natural gas properties. The increase in net cash used in investing activities of $38.2 million in 2011 compared to 2010 is due to an increase in development expenditures offset by a decrease in expenditures for property acquisitions in 2011 as compared with 2010. The increase in net cash used in investing activities of $634.1 million in 2010 compared to 2009 is due to an increase in development expenditures and an increase in acquisition activities in 2010 compared with 2009.

Net cash provided by financing activities in 2011 includes net borrowings under our credit facility of $361.5 million, partially offset by the repurchase of $94.7 million aggregate principal amount of our 2014 Notes. Net cash provided by financing activities in 2010 included net proceeds of $224.0 million from the issuance of 8 million shares of our Class A Common Stock and $300.0 million aggregate principal amount of our 2020 Notes, partially offset by debt issuance costs of $15.2 million and net repayment of our outstanding borrowings under our credit facility and our money market line of credit of $196.7 million. Net cash used in financing activities in 2009 included $585.1 million net repayment on our outstanding borrowings under our credit facility and money market line of credit and $24.0 million of debt issuance costs, partially offset by the issuance of $450.0 million aggregate principal amount of our 2014 Notes for net proceeds of $435.0 million after underwriting discounts and estimated offering expenses.

Capital Expenditures. The following is a summary of the drilling and development capital expenditures:

(in thousands)	Year Ended December 31,		
Asset Team	2011	2010	2009
S. Midway	$47,000	$35,000	$24,000
N. Midway	156,000	67,000	32,000
Permian	218,000	42,000	—
Uinta	63,000	50,000	6,000
E. Texas	11,000	71,000	47,000
Piceance	31,000	45,000	26,000
Corporate	1,000	—	—
Total	$527,000	$310,000	$135,000

We continually evaluate our capital needs and compare them to our capital resources. We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. We expect our 2012 capital budget to be between $600 million and $650 million, assuming an average commodity price of $90 WTI, and we expect to fund our 2012 capital budget largely with net cash provided by our operating activities. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we may adjust our capital budget accordingly or adjust borrowings under our credit facility, as needed. Substantially all of our 2012 capital expenditure budget is directed towards our oil assets, targeting oil production growth of approximately 20%.

Although we have no specific budget for property acquisitions in 2012, we will continue to selectively pursue property acquisitions that complement our existing core property base. We believe that, should attractive acquisition opportunities be presented, we will be able to finance additional capital expenditures with cash flows from operating activities, borrowings under our credit facility, issuances of additional debt or equity, or agreements with industry partners.

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Contractual Obligations

Our contractual obligations as of December 31, 2011 are as follows:

(in millions)	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt and interest(1)	$1,780.2	$83.9	$83.9	$417.9	$47.5	$769.4	$377.6
Asset retirement obligations(2)	64.0	4.7	3.8	3.6	3.6	3.6	44.7
Operating leases(3)	11.8	2.8	2.8	2.6	2.2	1.4	—
Other commitments (4)	31.3	14.2	11.4	1.8	1.9	2.0	—
Drilling rig commitments(5)	7.0	7.0	—	—	—	—	—
Firm natural gas transportation contracts(6)	263.5	29.7	30.2	32.7	32.6	32.5	105.8
Derivative liabilities(7)	35.9	20.4	15.5	—	—	—	—
Total	$2,193.7	$162.7	$147.6	$458.6	$87.8	$808.9	$528.1

(1) Long-term debt consists of our 2016 Notes, 2014 Notes, 2020 Notes and outstanding debt under our credit facility, and assumes no principal repayment until the due date of the instruments. Cash interest expense on our credit facility is estimated assuming no principal repayment until the instrument due date and is estimated at a constant interest rate of 2.018%.

(2) The ultimate settlement amounts and the timing of the settlement of such obligations are unknown because they are subject to, among other things, federal, state, local, and tribal regulation and economic factors. See Part II, Item 7A. "Critical Accounting Policies and Estimates" for a more detailed discussion of the nature of the accounting estimates involved in estimating asset retirement obligations.

(3) Operating leases relate primarily to obligations associated with our office facilities, equipment, vehicles and aircraft.

(4) Other commitments relate primarily to natural gas purchases, cogeneration facility management services and equipment rentals.

(5) We currently have four drilling rigs under contract that require minimum payments for the full contract term or penalties upon early termination. All these drilling rig contracts expire in 2012. Contracts for all other rigs performing work for us at December 31, 2011 were on a well-by-well basis and could be released without penalty at the conclusion of drilling on the current well, and therefore have not been included in the table above.

(6) We enter into certain firm commitments to transport natural gas production to market and to transport natural gas for use in our cogeneration and conventional steam generation facilities. These commitments generally require a minimum monthly charge regardless of whether the contracted capacity is used or not. These commitments include a transportation agreement with Questar Pipeline Company for an average of 6,200 MMBtu/D of firm transportation over a period of eight years, based on the expectation that the expansion of the Chipeta Processing LLC natural gas plant will be completed and transportation under this contract will begin July 1, 2012.

(7) Derivative liabilities represent the fair value of our derivatives presented as net liabilities in our Balance Sheets as of December 31, 2011. These amounts represent open commodity derivative instruments that were in a net liability position with the counterparty at December 31, 2011. Our remaining commodity derivative instruments were in a net asset position with the counterparty at December 31, 2011. The ultimate settlement amounts of our derivative liabilities are unknown because they are subject to continuing market fluctuations. See Notes 8 and 9 to the Financial Statements. Also, See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for further details concerning our hedging activities.

Based on current oil and natural gas prices and anticipated levels of production, we believe that we have sufficient liquidity and capital resources to execute our business plans over the next 12 months and for the foreseeable future. In addition, with our expected cash flow streams, commodity price hedging strategies, current liquidity levels, access to debt and equity markets and flexibility to modify future capital expenditure programs, we expect to be able to fund all planned capital programs, dividend distributions and debt repayments; while complying with our debt covenants and meeting any other obligations that may arise from our oil and natural gas operations. However, if our revenue and cash flow decrease in the future as a result of a deterioration in domestic and global economic conditions or a significant decline in commodity prices, we may elect to reduce our planned capital expenditures. We believe that this financial flexibility to adjust our spending levels will provide us with sufficient liquidity to meet our financial obligations. See Part I, Item 1A—"Risk Factors," for a discussion of the risks and uncertainties that affect our financial condition, results of operation, and operating cash flows.

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 and to disclose 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.

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Successful Efforts Method of Accounting. We account for our oil and natural gas exploration and development costs using the successful efforts method. Geological and geophysical costs 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 costs of development wells are capitalized whether productive or nonproductive.

Impairment of Oil and Natural Gas Properties. Proved oil and natural gas properties are reviewed for impairment on a field-by-field basis, annually or when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of our oil and natural gas properties and compare these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, and discount rates commensurate with the risk associated with realizing the projected cash flows. Due to the impact of lower natural gas prices, we recorded an impairment of $625.0 million related to our E. Texas natural gas assets. See Notes 9 and 11 to the Financial Statements.

Unproved oil and natural gas properties are periodically assessed for impairment on a project-by-project basis. The impairment assessment is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize an impairment loss at that time.

Oil and Natural Gas Reserves. Estimated proved reserves included in this Annual Report on Form 10-K were prepared by DeGolyer and MacNaughton (D&M), an independent petroleum engineering consulting firm that has provided consulting services throughout the world for over 70 years. Estimated proved reserves presented in this report are calculated in accordance with the SEC's "Modernization of Oil and Gas Reporting" rule which was first effective for December 31, 2009 reporting. These rules include calculating estimated proved reserves based on the average prices during the twelve-month period prior to the reporting date, with such prices determined as the unweighted arithmetic average of the first-day-of-the month prices for each month within the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

There are numerous uncertainties 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 natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition to the physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, economic factors such as changes in commodity prices or development and production expenses, may require revision of such estimates. Accordingly, oil and natural 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.

Depreciation, Depletion and Amortization (DD&A-oil and natural gas production). The provision for DD&A-oil and natural gas production is calculated on a field-by-field basis using the unit-of-production method. Projected future production rates, the timing of future capital expenditures as well as changes in commodity prices, may significantly impact estimated reserve quantities. DD&A—oil and natural gas production 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 oil and natural gas production, which in turn reduces net earnings. 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.

Capitalized Interest. Acquisition costs of proved undeveloped and unproved properties qualify for interest capitalization during a period if interest cost is incurred and activities necessary to bring the properties into a productive state are in progress. As wells are drilled in a field with proved undeveloped or unproved reserves, a portion of the acquisition costs are either redesignated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, we determine the amount of the acquisition cost to re-designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

Purchase Price Allocations. We occasionally acquire assets and assume liabilities in transactions accounted for as business combinations. In connection with a purchase business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess of the purchase price over amounts assigned to assets and liabilities is recorded as goodwill. Any excess of amounts assigned to assets and liabilities over the purchase price is recorded as a gain on bargain purchase. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and natural gas properties. Due to the unavailability of relevant comparable market data, a discounted cash flow method is used to determine the fair value of proved properties. The discounted cash flow method estimates future cash flows based on management's expectations of future recoverable proved and risk-adjusted probable reserves, commodity prices based on commodity futures price strips, production timing, drilling and production costs and a risk-adjusted discount rate.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A-oil and natural gas production, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value.

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 accumulated other comprehensive loss 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 statements of operations 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. 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, and time to maturity and credit risk. The values we report in our financial statements change 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 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.

Due to the volatility of oil and natural gas prices and interest rates, the estimated fair values of our derivative instruments are subject to large fluctuations from period to period. See Part II, Item 7A—"Quantitative and Qualitative Disclosures about Market Risk" for a sensitivity analysis of the change in net fair values of our commodity and interest rate derivatives based on a hypothetical change in commodity prices and interest rates.

Income Taxes and Uncertain Tax Positions. Income taxes are recorded for the income tax effects of transactions reported in the financial statements and consist of income 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 income tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted income tax rates to the differences between the financial statements and income tax reporting. We routinely assess the realizability of our deferred income tax assets, and a valuation allowance is recognized if it is determined that deferred income tax assets may not be fully utilized in future periods. We consider future taxable earnings in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable earnings, 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 income tax asset valuation allowances in a future period. We are subject to taxation in many jurisdictions, and the calculation of our income tax liabilities involves dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. We recognize certain income 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 an income 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 natural 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 natural 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 the passage of time impact net earnings as accretion expense. The related capital cost, including revisions thereto, is charged to expense through DD&A-oil and natural gas over the life of the oil and natural 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 natural gas operating costs and the liability, if applicable, recorded on our Balance Sheets.

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 natural 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. A portion of the capital costs of the cogeneration facilities is allocated to DD&A—oil and natural gas production.

Impact of Recently Issued Accounting Standard Updates

For further information on the effects of recently adopted accounting pronouncements and the potential effects of new accounting pronouncements, see Note 1 to the Financial Statements.

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Reconciliation of Non-GAAP Measures

Discretionary Cash Flow. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of discretionary cash flow to cash provided by operating activities, the most directly comparable GAAP measure, for the period presented.

	Year Ended December 31:		
(in millions)	2011	2010	2009
Net cash provided by operating activities	$455.9	$367.2	$212.6
Add back: Net increase (decrease) in current assets	26.3	(12.5)	10.1
Add back: Net decrease (increase) in current liabilities including book overdraft	(20.3)	(12.7)	33.6
Add back: Unwind interest swap payments	—	10.8	—
Add back: Recovery of Flying J bad debt	—	38.5	—
Discretionary cash flow	$461.9	$391.3	$256.3

Operating Margin per BOE. Operating margin per barrel consists of oil and natural gas revenues less oil and natural gas operating expenses and production taxes divided by the total barrels sold during the period. Management uses operating margin per barrel as a measure of profitability and believes it provides useful information to investors because it relates our oil and natural gas revenue and oil and natural gas operating expenses to our total units of production providing a gross margin per unit of production, allowing investors to evaluate how our profitability varies on a per unit basis each period.

	Year Ended December 31:		
(per BOE)	2011	2010	2009
Average sales price including cash derivative settlements	$65.68	$53.84	$46.02
Average operating costs—oil and natural gas production	18.23	15.95	14.66
Average production taxes	2.58	1.93	1.70
Average operating margin	$44.87	$35.96	$29.66

Pre-Tax PV10. Pre-tax PV10 is defined as standardized measure of discounted future net cash flows before the effect of income taxes. We present pre-tax PV-10 because it is a widely used industry standard which management believes is useful when comparing our asset base and performance to other comparable oil and natural gas exploration and production companies. The following table reconciles pre-tax PV-10 to the standardized measure of discounted future net cash flows:

	Year Ended December 31,	
(in thousands)	2011	2010
Standardized measure of oil and gas	$4,035,279	$2,799,156
Discounted future cash flow from income taxes	1,669,768	1,035,021
Discounted future net cash flow before income taxes	$5,705,047	$3,834,177

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Our primary market risk relates to the prices we receive for our oil and natural gas production. Historically the markets for oil and natural gas have been volatile and are likely to continue to be volatile in the future. We use various derivative instruments to manage our exposure to commodity price risk. All derivative instruments are recorded on the balance sheet at fair value. If a derivative instrument does not qualify for hedge accounting or we do not elect to use hedge accounting, the changes in fair value, both realized and unrealized, are recorded as unrealized gains or losses in realized and unrealized (gain) loss on derivatives, net in our Statements of Operations. Cash flows from operating activities are impacted to the extent that actual cash settlements under these derivative instruments result in payments to or from the counterparty, and such cash settlement gains and losses are recorded under realized and unrealized (gain) loss on derivatives, net in our Statements of Operations. See Notes 8 and 9 to the Financial Statements. We do not have any current derivative instruments for which we have elected hedge accounting.

Currently, our derivative instruments are in the form of swaps and collars. However, we may use a variety of derivative instruments in the future to hedge WTI or other index prices. A two-way collar is a combination of options, a sold call and purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. We utilize costless collars which are options positions by which the proceeds from the sale of the call option fund the purchase of a put option. A hypothetical $10 increase in the oil prices used and $1 increase in the natural gas prices used to calculate the fair values of our derivative instruments at December 31, 2011 would decrease the respective fair value of crude oil and natural gas derivative instruments at December 31, 2011 by $96.9 million and $3.3 million, respectively. A hypothetical $10 decrease in oil prices and a $1 decrease in natural gas prices used to calculate the fair values of our derivative instruments at December 31, 2011 would increase the respective fair value of oil and natural gas derivative instruments at December 31, 2011 by $83.1 million and $3.3 million, respectively. As our natural gas production continues to decrease and our use of natural gas for steaming operations increase, we may become a net consumer of natural gas and may enter into derivative instruments to limit our exposure to future increases in natural gas prices.

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The following table summarizes our commodity hedge positions as of December 31, 2011:

Term	Average Barrels Per Day	Average Prices
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2012	1,000	$65.00/$85.00/$97.25
Full year 2012	1,000	$70.00/$87.00/$105.00
Full year 2012	1,000	$70.00/$88.00/$106.00
Full year 2012	1,000	$60.00/$80.00/$96.92
Full year 2012	1,000	$60.00/$80.00/$120.00
Full year 2012	1,000	$70.00/$88.15/$100.00
Full year 2012	1,000	$70.00/$86.85/$100.00
Full year 2012	1,000	$69.70/$85.00/$100.00
Full year 2012	1,000	$70.00/$87.00/$108.50
Full year 2012	1,000	$70.00/$90.00/$116.50
Full year 2012	1,000	$70.00/$90.00/$120.00
Full year 2012	1,000	$70.00/$95.00/$120.10
Full year 2012	1,000	$77.95/$105.00/$115.00
Full year 2012	1,000	$80.00/$107.00/$119.60
Full year 2012	500	$70.00/$90.00/$100.00
Full year 2012	500	$70.00/$90.00/$100.00
Full year 2012	1,000	$75.00/$90.00/$101.85
Full year 2012 (1)	1,000	$70.00/$85.00/$92.00
Full year 2012 (1)	2,000	$70.00/$80.00/$83.00
Full year 2012 (1)	1,500	$75.00/$90.00/$97.50
Full year 2012 (1)	500	$75.00/$90.00/$106.90
Full year 2013	1,000	$65.00/$85.00/$97.25
Full year 2013	1,000	$70.00/$87.00/$105.00
Full year 2013	1,000	$70.00/$88.00/$106.00
Full year 2013	1,000	$60.00/$80.00/$103.30
Full year 2013	1,000	$70.00/$88.15/$100.00
Full year 2013	1,000	$70.00/$86.85/$100.00
Full year 2013	1,000	$69.70/$85.00/$100.00
Full year 2013	1,000	$70.00/$87.00/$108.50
Full year 2013	1,000	$70.00/$90.00/$116.50
Full year 2013	1,000	$70.00/$90.00/$120.00
Full year 2013	1,000	$70.00/$95.00/$120.10
Full year 2013	1,000	$77.95/$105.00/$115.00
Full year 2013	1,000	$80.00/$107.00/$119.60
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	500	$70.00/$90.00/$100.00
Full year 2013	1,000	$75.00/$90.00/$101.85
Full year 2014	1,000	$77.95/$105.00/$115.00
Full year 2014	1,000	$80.00/$107.00/$119.60

Term	Average MMBtu Per Day	Average Prices
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2012	5,000	$7.16
Full year 2012	5,000	$5.75
Natural Gas Sales (NYMEX HH) Collars		
Full year 2012	5,000	$6.00/$7.70
Natural Gas Sales (NYMEX HH to NGPL-Tex OK) Basis Swaps		
Full year 2012	2,500	$0.44
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2012	2,500	$0.32

(1)

In the third quarter of 2011, we converted several of our two-way oil collars to three-way oil collars. There were no payments made or received as a result of these transactions.

Excluded from the table above are our calendar month average swaps, which protect us from variances in market pricing conditions of certain of our sales contracts. These derivative contracts protect 5,000 BOE/D of our Permian sales volumes and have differentials of $0.075 to $0.080 during 2012 and $0.070 to $0.075 during 2013.

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Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit facility. Our credit facility allows us to fix the interest rate for all or a portion of the principal balance for a period up to 12 months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit facility that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate debt. At December 31, 2011, our outstanding principal balance under our credit facility was $531.5 million and the weighted average interest rate on the outstanding principal balance was 2.018%. At December 31, 2011, the carrying amount approximated fair market value. Assuming a constant debt level of $1.4 billion, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $3.3 million over a 12-month time period.

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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.

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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, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 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, 2011, 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 8 to the financial statements, the Company discontinued hedge accounting effective January 1, 2010.

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 28, 2012

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BERRY PETROLEUM COMPANY
Balance Sheets
December 31, 2011 and 2010
(In Thousands, Except Share Information)

	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$298	$278
Short-term investments	65	65
Accounts receivable	115,952	93,406
Deferred income taxes	13,779	32,342
Derivative instruments	6,117	2,742
Assets held for sale	14,622	—
Prepaid expenses and other	16,801	14,033
Total current assets	167,634	142,866
Oil and natural gas properties (successful efforts basis), buildings and equipment, net	2,531,393	2,655,792
Derivative instruments	7,027	2,054
Other assets	28,898	37,904
	$2,734,952	$2,838,616
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$126,489	$106,459
Revenue and royalties payable	49,253	37,812
Accrued liabilities	35,066	36,234
Line of credit	—	5,300
Derivative instruments	20,365	84,846
Total current liabilities	231,173	270,651
Long-term liabilities:		
Deferred income taxes	185,450	329,207
Senior secured revolving credit facility	531,500	170,000
8.25% Senior subordinated notes due 2016	200,000	200,000
10.25% Senior notes due 2014, net of unamortized discount of $6,564 and $11,035, respectively	348,692	438,965
6.75% Senior notes due 2020	300,000	300,000
Asset retirement obligations	64,019	53,443
Derivative instruments	15,505	33,526
Other long-term liabilities	17,884	18,271
	1,663,050	1,543,412
Commitments and contingencies (Note 10)		
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; 52,067,994 and 51,426,232 shares issued and outstanding, respectively	521	514
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $0.50 per share)	18	18
Capital in excess of par value	350,158	327,369
Accumulated other comprehensive loss	(5,517)	(43,806)

Retained earnings	495,549	740,458
Total shareholders' equity	840,729	1,024,553
	$2,734,952	$2,838,616

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

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BERRY PETROLEUM COMPANY
Statements of Operations
Years ended December 31, 2011, 2010 and 2009
(In Thousands, Except Per Share Data)

	2011	2010	2009
REVENUES			
Sales of oil and natural gas	$870,773	$619,608	$500,532
Sales of electricity	34,953	34,740	36,065
Natural gas marketing	13,832	22,162	22,806
Settlement of Flying J bankruptcy claim	—	21,992	—
Gain on sale of assets	—	—	826
Interest and other income, net	1,784	3,300	1,810
	921,342	701,802	562,039
EXPENSES			
Operating costs—oil and natural gas production	237,476	190,218	156,612
Operating costs—electricity generation	25,690	31,295	31,400