SM Energy Co
Form 10-K
February 25, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2010

or

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

Commission file number 001-31539

SM ENERGY COMPANY

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**41-0518430** (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	**80203** (Zip Code)

(303) 861-8140

(Registrant s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common stock, $.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No o

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the 62,549,910 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the Company s common stock on June 30, 2010, the last business day of the registrant s most recently completed second fiscal quarter, of $40.16 per share, as reported on the New York Stock Exchange; was $2,512,004,386. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the Company to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 18, 2011, the registrant had 63,435,434 shares of common stock outstanding, which is net of 102,635 treasury shares held by the Company.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant s definitive proxy statement relating to its 2011 annual meeting of stockholders to be filed within 120 days after December 31, 2010.

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PART I

When we use the terms SM Energy, the Company, we, us, or our, we are referring to SM Energy Company, formerly named St. Mary Land Exploration Company or referred to as St. Mary, and its subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under Glossary of Oil and Gas Terms. Throughout this document we make statements that may be classified as forward-looking. Please refer to the Cautionary Information about Forward-Looking Statements section of this document for an explanation of these types of statements.

ITEMS 1. and 2. BUSINESS and PROPERTIES

General

We are an independent energy company engaged in the acquisition, exploration, exploitation, development and production of natural gas and crude oil in North America, with a focus on oil- and liquids-rich resource plays. We were founded in 1908 and incorporated in Delaware in 1915. Our initial public offering of common stock was in December 1992. Our common stock trades on the New York Stock Exchange under the ticker symbol SM.

Our principal offices are located at 1775 Sherman Street, Suite 1200, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

Our business strategy is to increase net asset value through attractive oil and natural gas investment activity while maintaining a conservative capital structure and optimizing capital expenditures. We focus our efforts on the exploration for, and the development of, onshore, lower-risk resource plays in North America. We believe our inventory of drilling locations is ideally suited to growing reserves and production due to predictable geology and lower-risk profile. Furthermore, our assets produce significant volumes of oil and NGLs that limit our exposure to the current lower natural gas price environment. Our strategy is based on the following points:

- leveraging our core competencies in replicating resource play success in the drilling, completion, and development of oil and natural gas reserves;

- focusing on resource plays with low-risk geology and high liquids content;

- exploiting our legacy assets and optimizing our asset base;

- selectively acquiring leasehold positions in new and emerging resource plays; and

- maintaining a strong balance sheet while funding the growth of our business.

Significant Developments in 2010

- *Focus on Resource Play Potential.* We have meaningful acreage positions in attractive resource plays in North America. We have approximately 250,000 net acres in the Eagle Ford shale play in South Texas, two-thirds of which we operate with an approximate 100 percent working interest. In the North Dakota portion of the Williston Basin, we have approximately 81,000 net acres that are prospective in the Bakken/Three Forks formations. Throughout 2010, we worked to advance our understanding of these liquids-rich resource plays. In the second half of 2010, we began accelerating the development of these plays based on the positive results we were realizing. We believe these two programs are large enough to allow us to gain economies of scale and improve our operational efficiencies in these plays. In addition to the these plays, we have acreage positions in the Granite Wash play in western Oklahoma and the Texas Panhandle, the Haynesville shale in East Texas and northern Louisiana, and the Woodford shale in eastern Oklahoma that provide additional drilling

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inventory, particularly in a higher natural gas price environment. During 2010, we further developed our knowledge of each of these plays and formed an exploration team focused on identifying and evaluating other resource play opportunities.

- *Increase in Year End Proved Reserve Estimates.* Our estimated proved reserves increased 27 percent to 984.5 BCFE at December 31, 2010, from 772.2 BCFE at December 31, 2009. We added 384.2 BCFE from our drilling program, the majority of which related to our activity in the Eagle Ford shale in South Texas and the Woodford shale in eastern Oklahoma. We sold 86.8 BCFE of proved reserves during the year related to non-strategic assets located primarily in our Rocky Mountain and Permian regions. We added 42.6 BCFE of estimated proved reserves as a result of price revisions in 2010. The prices used in the calculation of proved reserve estimates as of December 31, 2010, were $79.43 per Bbl and $4.38 per MMBTU for oil and natural gas, respectively. These prices were 30 percent and 13 percent higher, respectively, than the prices used in 2009. Performance revisions in 2010 resulted in a net 11.2 BCFE decrease in our estimate of proved reserves. While we recognized positive performance revisions in every region on proved developed properties, we had approximately 19.3 BCFE of negative performance revisions related to estimated proved undeveloped reserves in primarily dry gas assets, resulting from lower gas prices and higher well costs on the economics of these assets. Lastly, we reduced estimated proved reserves by 6.7 BCFE by removing proved undeveloped reserves related to assets that reached aging limitations, as mandated by the Securities and Exchange Commission (SEC). Please refer to **Core Operational Areas** and **Reserves** later in this section for additional discussion concerning our 2010 proved reserves.

- *Production*. During 2010, our average daily production was 196.9 MMcf of gas and 17.4 MBbl of oil, for an average equivalent production rate of 301.4 MMCFE per day, which was up slightly compared with 298.8 MMCFE per day for 2009. Adjusting for production from properties sold during 2010 as part of our divestiture efforts over the last few years, production from retained properties has increased 12 percent from 262.3 MMCFE per day in 2009 to 294.0 MMCFE per day in 2010. Please refer to **Core Operational Areas** and **Reserves** later in this section for additional discussion concerning our 2010 production.

- *Capital Investment.* During 2010, we incurred costs of $877.4 million for drilling and exploration activities and acquisitions, compared with $419.0 million in 2009. The increase in capital investment reflects our increased confidence in our drilling inventory, particularly in plays with significant oil and rich-gas components. Please refer to **Core Operational Areas** later in this section for additional discussion concerning our 2010 capital investments.

- *Volatility in Commodity Prices.* Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, natural gas, and NGLs, which can fluctuate dramatically. Oil prices gradually increased throughout 2010. The spot price for NYMEX crude oil hit a two-year high of $91.57 per Bbl during the last week of December. The spot price for NYMEX crude oil was at its lowest of $63.14 per Bbl in May. The average spot price for oil during 2010 was $79.51 per Bbl.

Natural gas prices continued to be volatile in 2010. The spot price for gas at Henry Hub, a widely-used industry measuring point, averaged $4.37 per MMBtu in 2010, with a high of $7.75 per MMBtu in January and a low of $3.10 per MMBtu in October. Natural gas prices continued to be under downward pressure in 2010 as a result of excess supply resulting from high levels of drilling activity across the United States, as well as tepid demand due to the economic recession in the United States.

- *Divestiture of Non-Strategic Properties.* We continuously look to high grade our portfolio of assets through the divestiture of non-strategic properties. The objective of these divestitures is to dispose of properties with high operating costs and/or limited future drilling or development potential to generate cash that can be used in the development of our resource plays and other general corporate purposes. During 2010,

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we sold 86.8 BCFE of reserves, the majority of which related to assets located in our Rocky Mountain and Permian regions. The following transactions represent the Company s most significant divestitures during 2010:

o *Legacy Divestiture.* On February 17, 2010, we sold certain non-strategic properties in Wyoming to Legacy Reserves Operating LP. Total cash received, before marketing costs and Net Profits Interest Bonus Plan (Net Profits Plan) payments, was $125.3 million. The final gain on divestiture activity related to this divestiture was approximately $66.7 million.

o *Sequel Divestiture.* On March 12, 2010, we sold certain non-strategic properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners, LLC. Total cash received, before marketing costs and Net Profits Plan payments, was $129.1 million. The final gain on divestiture activity related to this divestiture was approximately $53.1 million.

o *Permian Divestiture.* On December 29, 2010, we sold certain non-strategic properties located in our Permian region. Total cash received, before marketing costs and Net Profits Plan payments, was $56.3 million. The final sale price is subject to normal post-closing adjustments and is expected to be finalized during the first half of 2011. The estimated gain on divestiture activity related to this divestiture is approximately $19.9 million and may be impacted by the forthcoming post-closing adjustments mentioned above.

o *Rockies Divestiture.* Subsequent to year end, we sold certain non-strategic oil and gas properties located in our Rocky Mountain region. Total cash received, before marketing costs and Net Profits Plan payments, was $44.4 million. The final sales price is subject to post-closing adjustments and is expected to be finalized during the first half of 2011.

Outlook for 2011

We enter 2011 with a capital budget of approximately $1.0 billion, of which approximately $830.0 million has been allocated to drilling activity focused on the development of our inventory of resource play opportunities. Please refer to **Core Operational Areas** below for detailed regional discussion of our 2011 capital budget and *Outlook for 2011* under Part II, Item 7 of this report.

As we enter the year, we are well positioned both financially and operationally. We have no debt maturities until 2012, when our credit facility matures and our outstanding convertible notes can either be put to us by the note holders or be called by us. Given our debt and asset levels, credit standing, and relationship with our bank group, we believe we will be able to extend our existing facility or obtain a replacement credit facility before our current credit facility matures in 2012. Given the current trading level of our common stock and our liquidity, it is likely that we will call the convertible notes in 2012. We have the option of settling the convertible notes with cash, common stock, or a combination of cash and common stock, the mix of which is at our discretion.

Subsequent to year end, the Company issued $350.0 million in aggregate principal amount of 6.625% senior unsecured notes (the 6.625% Senior Notes). The 6.625% Senior Notes mature on February 15, 2019. We used a portion of the proceeds from our 6.625% Senior Notes offering to repay our outstanding balance under our credit facility. The remaining proceeds will be used to help fund our 2011 capital program and for general corporate purposes. Please refer to Note 5 Long-term Debt under Part IV, Item 15 of this report for additional discussion.

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Core Operational Areas

Our operations are currently concentrated onshore in five core operating areas in the United States. The following table summarizes the production, estimate of proved reserves, and PV-10 reserve value of our core operating areas as of December 31, 2010:

	ArkLaTex	Mid-Continent	South Texas & Gulf Coast	Permian	Rocky Mountain	Total(1) (2)
Proved Reserves						
Oil (MMBbl)	0.3	1.3	9.7	13.7	32.4	57.4
Gas (Bcf)	135.9	286.1	149.1	31.4	37.5	640.0
Equivalents (BCFE)	137.9	293.7	207.3	113.9	231.8	984.5
Relative percentage	14%	30%	21%	12%	24%	100%
Proved Developed %	64%	68%	47%	87%	88%	70%
PV-10 Values (in millions)						
Proved Developed	$ 147.1	$ 400.5	$ 376.1	$ 428.0	$ 701.8	$ 2,053.5
Proved Undeveloped (3)	19.0	68.0	130.0	42.6	31.2	290.8
Total Proved	$ 166.1	$ 468.5	$ 506.1	$ 470.6	$ 733.0	$ 2,344.3
Relative percentage	7%	20%	22%	20%	31%	100%
Production						
Oil (MMBbl)	0.1	0.2	1.0	1.7	3.3	6.4
Gas (Bcf)	13.9	32.1	16.4	4.3	5.2	71.9
Equivalent (BCFE)	14.4	33.4	22.7	14.7	24.9	110.0
Avg. Daily Equivalents (MMCFE/d)	39.3	91.5	62.1	40.2	68.3	301.4
Relative percentage	13%	30%	21%	13%	23%	100%

(1) Totals may not add due to rounding.

(2) Included in the total are approximately 11 BCFE related to non-strategic properties that we divested subsequent to December 31, 2010.

(3) We record estimates of proved undeveloped for locations with a negative PV-10 value if we have the intent to drill the location and believe it will generate positive undiscounted net cash flow and meet our economic criteria.

South Texas & Gulf Coast Region. Operations for the region are managed from our office in Houston, Texas. Our current operations in the South Texas & Gulf Coast region center on our Eagle Ford shale program. Since 2007 we have expanded our acreage position to approximately 250,000 net acres, of which roughly two-thirds is operated by us with a working interest of approximately 100 percent. Our acreage position covers a significant portion of the greater Eagle Ford play, including acreage in the oil, the rich-gas, and the dry gas windows of the play. During the first half of 2010, we worked to increase our understanding of the play and focused our efforts on mitigating risk in our drilling and development programs, particularly with respect to delineating the respective product windows. On our operated acreage position, we operated two drilling rigs throughout the year which tested a large amount of our acreage. As a result of the positive results we experienced in our operated program, we began making commitments in the second half of the year for takeaway capacity and to secure drilling and completion services that will enable us to increase our activity in 2011 and beyond. In our non-operated Eagle Ford program, which represents approximately one-third of our total acreage position, the operator of the program steadily increased its drilling rig count throughout 2010. In addition to participating in our non-operated drilling program, we also participate in the construction of midstream assets to service the development of the shared acreage position. Substantially all of our capital deployed in the South Texas & Gulf Coast region in 2010 targeted our Eagle Ford shale program. Our capital investment, production, and reserves all increased considerably in 2010 as a result of our focused efforts in our Eagle Ford shale program. Our capital expenditures for exploration, development, and acquisition activity in our South Texas & Gulf Coast region increased significantly from $115.1 million in 2009 to $456.2 million in 2010.

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Production in 2010 for the South Texas & Gulf Coast region was 22.7 BCFE, an increase of 134 percent from the 9.7 BCFE produced in 2009. Estimated proved reserves at the end of 2010 increased 290 percent to 207.3 BCFE, compared with 53.2 BCFE reported in the prior year. The increase in production and proved reserves reflect the significant increase in activity on both the operated and non-operated portions of our Eagle Ford shale program. Production from portions of our operated acreage was limited for much of the year as a result of insufficient natural gas takeaway capacity. By year end, we had reached an agreement to increase our takeaway capacity in the affected area.

Our plans for 2011 in the South Texas & Gulf Coast region are to continue focusing exclusively on the Eagle Ford shale. We begin 2011 operating two drilling rigs in Webb and LaSalle Counties in South Texas. Over the course of the year, we plan to increase our operated rig count to five or six drilling rigs, the vast majority of which will target portions of our acreage containing high BTU gas and condensate. Most of the wells planned for the year will be in the Briscoe and Galvan Ranch areas where we were active during 2010. A higher level of activity is also planned for LaSalle County, Texas in order to test and delineate our acreage in that area. In addition, a number of projects, such as retained energy fracture stimulations and reduced spacing pilots, are planned for next year across the play.

In the non-operated portion of our Eagle Ford shale position, seven rigs are currently operating. The operator has indicated it plans an increase to ten drilling rigs by the end of the first quarter of 2011. In addition, the operator is actively pursuing a partial sale or farm-down of its portion of the shared acreage, which could result in a further increase in drilling activity.

We have allocated approximately $500 million of our 2011 capital budget to our total Eagle Ford shale drilling program. Based on the activity levels contemplated above, capital expenditures net to us would be in excess of this amount. We have also initiated a marketing effort to sell down or joint venture a portion of our total Eagle Ford shale position. Although specifics related to the contemplated transaction are still being determined, we estimate that we could sell down or joint venture 20 to 30 percent of our total acreage position, resulting in a net investment by us in our Eagle Ford program in 2011 of approximately $500 million.

Rocky Mountain Region. Operations for the region are managed from our office in Billings, Montana. Our capital investments in 2010 were primarily focused on the Bakken/Three Forks formations in the Williston Basin in Montana and North Dakota. During 2010, we were successful in testing prospects further west of the bulk of the industry s development activity in North Dakota. Our 2010 capital expenditures for exploration, development, and acquisition activity in the Rocky Mountain region increased from $51.2 million in 2009 to $158.5 million as a result of our continued focus on oil programs.

Estimated proved reserves for our Rocky Mountain region were 231.8 BCFE at year end compared with 260.3 BCFE as of the end of 2009. The decrease in proved reserves is the result of selling 71.7 BCFE of proved reserves in the region during the year. This decrease was partially offset by net positive price and engineering revisions of 16.7 BCFE and positive drillings adds of 51.3 BCFE. Our program targeting the Bakken/Three Forks formations contributed the majority of our drilling additions in this region. Total regional production for 2010 was 24.9 BCFE, which was down 25 percent from 33.3 BCFE in 2009 as a result of our Legacy and Sequel divestitures that closed in the first quarter of 2010. Adjusting for the effect of these divestitures, production in the region increased 1.4 BCFE, or six percent, year over year.

We plan to invest approximately $170 million in 2011 on drilling projects targeting the Bakken/Three Forks formations in the Williston Basin. We plan to operate two drilling rigs during the first half of 2011, with the planned addition of a third rig at mid-year. Substantially all of this activity is expected to occur in McKenzie and Divide Counties, North Dakota. Operations in McKenzie County will focus on the horizontal Bakken formation in our Raven prospect area in the western portion of the county. We will operate approximately two-thirds of this activity. Our activity in Divide County will target the Three Forks formation and will be entirely operated by us. We have also budgeted $25 million for drilling projects targeting the Niobrara formation in the northern portion of the DJ Basin in southeastern Wyoming, focusing on acreage near the

Silo Field in Laramie County.

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Mid-Continent Region. Operations for the region are managed from our office in Tulsa, Oklahoma. Our current operations in the Mid-Continent region are focused on the horizontal development of the Woodford shale in the Arkoma Basin in eastern Oklahoma and horizontal development of the Granite Wash formation in western Oklahoma and the Texas Panhandle. The Mid-Continent region also manages our Marcellus shale activity in north central Pennsylvania. We continued our successful development of the Woodford shale throughout 2010, with a particular focus on multi-well (simul-frac) completions, where multiple wells are completed at the same time. We focused our activity in the Woodford shale on portions of our acreage position that contained richer gas. Our 2010 Granite Wash program was focused on assessing the horizontal potential of our approximately 34,000 net acres in the play. We tested several intervals with varying degrees of success during the year and also participated in a number of non-operated wells. Activity in our Marcellus program during the year involved the drilling and completion of two wells and the completion of associated pipeline infrastructure. Late in 2010, we began a marketing process to divest our entire Marcellus position. We continue to explore our options to monetize all or a portion of our Marcellus assets. In 2010 we incurred costs of $124.5 million in the Mid-Continent region for exploration, development, and acquisition activity, which is 17 percent more than the $106.8 million incurred in 2009.

Our Mid-Continent region production in 2010 was 33.4 BCFE, a slight decrease from the 36.0 BCFE produced in 2009. Proved reserves at the end of 2010 were 293.7 BCFE, a considerable increase of 31 percent from the 223.5 BCFE reported for the prior year. Our horizontal Woodford shale program, as well as our assets in the Anadarko Basin targeting the Granite Wash formation, contributed the majority of our 100.4 BCFE of reserve additions.

The Company plans to invest approximately $60 million in 2011 in horizontal wells targeting the Granite Wash formation. Two operated drilling rigs will be required next year to execute this drilling program. We will operate over 65 percent of this activity. The economics of these projects benefit from the contribution of higher BTU natural gas and condensate in the production stream. No meaningful activity is planned for our Woodford shale program in 2011 due to the current outlook for natural gas prices. However, an increase in natural gas prices or a decrease in the costs of drilling and completing these wells could result in increased activity in the play.

ArkLaTex Region. Our operations for the region are managed from our office in Shreveport, Louisiana. Our 2010 capital investments were primarily focused on the Haynesville shale in East Texas and North Louisiana. Our 2010 capital expenditures for exploration, development, and acquisition activity in our ArkLaTex region decreased from $65.7 million in 2009 to $47.6 million. Our activity level in the Haynesville did not change significantly from what we planned at the beginning of the year, because our capital requirements in this play were substantially reduced as a result of the carry and earning agreement we entered into in the second quarter of 2010. The region s 2010 production was 14.4 BCFE, which was relatively flat when compared with 2009 production of 14.9 BCFE. Our 2010 year end proved reserves were 137.9 BCFE, which is 15 percent higher than the 2009 year end proved reserves of 120.0 BCFE. The increase in proved reserves is primarily the result of drilling additions in the Haynesville shale.

We have budgeted approximately $35 million for Haynesville shale activity in 2011 comprised of five gross operated horizontal wells. The majority of costs will be carried under the carry and earning agreement covering a portion of our acreage position in East Texas. We will also participate in approximately 20 gross (approximately two net) partner-operated horizontal wells in 2011.

We own approximately 22,000 net acres in the East Texas Shelby Trough that is prospective for both the Haynesville and Bossier shales, as well as other shallower productive zones. We are currently exploring a number of options for this acreage position which would allow us to drill or participate in enough wells in 2011 and early 2012 to hold substantially all of this acreage, while minimizing the amount of capital deployed by us. We would need to drill 12 gross wells in 2011, in addition to the operated wells discussed above, and eight gross wells in 2012 to hold all of this acreage.

Permian Region. Operations for the region are managed from our office in Midland, Texas. The Permian region area covers a significant portion of western Texas and eastern New Mexico and is one of the

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major producing basins in the United States. Our primary focus in this region is the Wolfberry tight oil play. We incurred costs of $85.4 million in the region in 2010 compared to $76.5 million in 2009 targeting the stacked carbonate Wolfcamp and Spraberry formations found in the basin. The region s 2010 production was 14.7 BCFE, which was relatively flat when compared with 2009 production of 15.1 BCFE. Proved reserves in this region as of the end of 2010 were 113.9 BCFE, which was relatively flat when compared to 2009 year end reserves of 115.2 BCFE.

We plan to spend approximately $40 million in the Permian region, with approximately $20 million expected to be invested in Wolfberry wells in 2011. The majority of this program will be operated by an outside partner. The remaining Permian region budget will be allocated to various other plays in the basin.

Reserves

The table below presents summary information with respect to the estimates of our proved oil and gas reserves for each of the years in the three-year period ended December 31, 2010. We engaged Ryder Scott Company, L.P. (Ryder Scott) to audit internal engineering estimates for at least 80 percent of the PV-10 value of our proved reserves in 2010, 2009, and 2008, excluding our coalbed methane properties. For 2008, Netherland, Sewell and Associates, Inc. (NSAI) prepared the reserve information for our coalbed methane projects at Hanging Woman Basin in the northern Powder River Basin and our non-operated coalbed methane interest in the Green River Basin. We divested all of our Hanging Woman Basin properties in the fourth quarter of 2009. The prices used in the calculation of proved reserve estimates as of December 31, 2010, were $79.43 per Bbl and $4.38 per MMBTU for oil and natural gas, respectively.

We emphasize that reserve estimates are inherently imprecise and that estimates of all new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved oil and gas reserves owned by us. Neither prices nor costs have been escalated. The following table should be read along with the section entitled Risk Factors Risks Related to Our Business - The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated. No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the SEC, since the beginning of the last fiscal year.

The ability to replace produced reserves is important to the sustainability of all exploration and production companies. Our 2010 corporate ratio of reserves replaced through drilling activity, excluding revisions, was 349 percent. There were no material acquisitions made in 2010. In 2010 all of our regions replaced their production for the year. This metric is calculated using information from the Oil and Gas Reserve Quantities section of Note 15 Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report. The numerator consists of the sum of discoveries and extensions and infill reserves in an existing proved field, which is then divided by production.

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We believe the concept of reserve replacement as described above, as well as permutations which may include other captions of the Oil and Gas Reserve Quantities section of Note 15 Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report, are widely understood by those who make investment decisions related to the oil and gas exploration business. For additional information about reserve replacement metrics, see the reserve replacement terms in the Glossary section of this report.

	As of December 31,		
	2010	**2009**	**2008**
Reserve data:			
Proved developed			
Oil (MMBbl)	46.0	48.1	47.1
Gas (Bcf)	411.0	342.0	433.2
BCFE	687.3	630.3	715.8
Proved undeveloped			
Oil (MMBbl)	11.4	5.7	4.3
Gas (Bcf)	229.0	107.5	124.2
BCFE	297.2	141.9	149.7
Total Proved			
Oil (MMBbl)	57.4	53.8	51.4
Gas (Bcf)	640.0	449.5	557.4
BCFE	984.5	772.2	865.5
Proved developed reserves %	70%	82%	83%
Proved undeveloped reserves %	30%	18%	17%
Reserve value data (in thousands):			
Proved developed PV-10	$ 2,053,556	$ 1,253,056	$ 1,214,380
Proved undeveloped PV-10	290,775	31,029	51,005
Total proved PV-10	$ 2,344,331	$ 1,284,085	$ 1,265,385
Standardized measure of discounted future cash flows	$ 1,666,367	$ 1,015,967	$ 1,059,069
Reserve replacement drilling and acquisitions, excluding revisions	349%	100%	174%
All in including sales of reserves	293%	14%	(93)%
All in excluding sales of reserves	372%	55%	(39)%
Reserve life (years)(1)	8.9	7.1	7.6

(1) Reserve life represents the estimated proved reserves at the dates indicated divided by actual production for the preceding 12-month period.

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The following table reconciles the standardized measure of discounted future net cash flows (GAAP) to the PV-10 value (Non-GAAP). The difference has to do with the PV-10 value measure excluding the impact of income taxes. Please see the definitions of standardized measure of discounted future net cash flows and PV-10 value in the Glossary.

	As of December 31, 2010	2009 (in thousands)	2008
Standardized measure of discounted future net cash flows	$ 1,666,367	$ 1,015,967	$ 1,059,069
Add: 10 percent annual discount, net of income taxes	1,294,632	732,997	724,840
Add: future income taxes	1,335,576	515,953	419,544
Undiscounted future net cash flows	$ 4,296,575	$ 2,264,917	$ 2,203,453
Less: 10 percent annual discount without tax effect	(1,952,244)	(980,832)	(938,068)
PV-10 value	$ 2,344,331	$ 1,284,085	$ 1,265,385

Proved Undeveloped Reserves

As of December 31, 2010, we had 297.2 BCFE of proved undeveloped reserves, which is an increase of 155.3 BCFE, or 109 percent, compared with 141.9 BCFE of proved undeveloped reserves at December 31, 2009. We added 203.0 BCFE of proved undeveloped reserves through our drilling program, 130.1 BCFE of which were extensions and discoveries, primarily in the Eagle Ford shale, the Bakken/Three Forks formations, and the Haynesville shale, as well as an additional 72.9 BCFE of infill proved undeveloped reserves that were mostly concentrated in our Woodford Shale properties in our Mid-Continent region and our Wolfberry properties in our Permian region. A positive revision of 4.8 BCFE was due to higher twelve-month average pricing primarily in the gas weighted regions, particularly in our ArkLaTex and Mid-Continent regions. We had a negative engineering revision of 19.3 BCFE due to increasing capital and operating costs in the less liquids-rich portions of our Woodford and Eagle Ford plays, causing those projects to no longer meet our internal investment hurdles. During the year, 9.9 BCFE were sold in divestitures primarily in our Rocky Mountain and Permian regions. We invested approximately $43.7 million to convert 16.6 BCFE of proved undeveloped reserves in 2010, mainly in our Wolfberry properties in the Permian region and Bakken/Three Forks properties in our Rocky Mountain region. We removed 6.7 BCFE of proved undeveloped reserves as a result of the five year limitation on the number of years that a proved undeveloped reserves may remain on the books without being developed. As of December 31, 2010, we have no material proved undeveloped reserves that have been on the books in excess of five years and we have recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well. As of December 31, 2010, estimated future development costs relating to proved undeveloped reserves are projected to be approximately $123 million, $240 million, and $122 million in 2011, 2012, and 2013, respectively.

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Internal Controls Over Reserves Estimate

Our policy regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserve quantities and values in compliance with the SEC s regulations. Responsibility for compliance in reserve bookings is delegated to our reservoir engineering group, which is led by our Vice President - Engineering and Evaluation.

Technical reviews are performed throughout the year by regional engineering and geologic staff who evaluate all available geological and engineering data. This data, in conjunction with economic data and ownership information, is used in making a determination of estimated proved reserve quantities. The reserve process is overseen by Dennis A. Zubieta, Vice President - Engineering and Evaluation. Mr. Zubieta joined us in June 2000 as a Corporate Acquisition & Divestiture Engineer, assumed the role of Reservoir Engineer in February 2003, and was appointed Reservoir Engineering Manager in August 2005. Mr. Zubieta was employed by Burlington Resources Oil and Gas Company (formerly known as Meridian Oil, Inc.) from June 1988 to May 2000 in various operations and reservoir engineering capacities. Mr. Zubieta received a Bachelor of Science degree in Petroleum Engineering from Montana Tech in May 1988. The regional technical staff does not report directly to Mr. Zubieta; they report to either regional technical managers or directly to the regional manager in their respective regions. This is intended to promote objective and independent analysis within the reserves estimation process.

Third-party Reserves Audit

An independent audit is performed by Ryder Scott using their own engineering assumptions and other economic data provided by us. A minimum of 80 percent of our total calculated proved reserve PV-10 value is audited by Ryder Scott. In the aggregate, the proved reserve values of the audited properties are required to be within 10 percent of our valuations for the total company as well as for each respective region. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services throughout the world for over seventy years. The technical person at Ryder Scott primarily responsible for overseeing our reserve audit is a Senior Vice President and received a Bachelor of Science degree in Petroleum Engineering from the University of Missouri at Rolla in 1970 and is a registered Professional Engineer in the States of Colorado and Utah. He is also a member of the Society of Petroleum Engineers. The Ryder Scott report is included as Exhibit 99.1.

In addition to a third party audit, our reserves are reviewed by senior management and the Audit Committee of our Board of Directors. Senior management, which includes the President and Chief Executive Officer, the Executive Vice President and Chief Operating Officer, and the Executive Vice President and Chief Financial Officer, is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The Audit Committee reviews the final reserves estimate in conjunction with Ryder Scott s audit letter. It may also meet with Ryder Scott representatives to discuss its processes and findings.

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Production

The following table summarizes the average volumes and realized prices, including and excluding the effects of hedging, of oil and gas produced from properties in which we held an interest during the periods indicated. Also presented is a production cost per MCFE summary:

	Years Ended December 31, 2010	2009	2008
Net production(1)			
Oil (MMBbl)	6.4	6.3	6.6
Gas (Bcf)	71.9	71.1	74.9
BCFE	110.0	109.1	114.6
Average net daily production(1)			
Oil (MBbl)	17.4	17.3	18.1
Gas (MMcf)	196.9	194.8	204.7
MMCFE	301.4	298.8	313.1
Average realized sales price, excluding the effects of hedging			
Oil (per Bbl)	$ 72.65	$ 54.40	$ 92.99
Gas (per Mcf)	$ 5.21	$ 3.82	$ 8.60
Per MCFE	$ 7.60	$ 5.65	$ 10.99
Average realized sales price, including the effects of hedging			
Oil (per Bbl)	$ 66.85	$ 56.74	$ 75.59
Gas (per Mcf)	$ 6.05	$ 5.59	$ 8.79
Per MCFE	$ 7.82	$ 6.94	$ 10.11
Production costs per MCFE			
Lease operating expense	$ 1.10	$ 1.33	$ 1.46
Transportation expense	$ 0.19	$ 0.19	$ 0.19
Production taxes	$ 0.48	$ 0.37	$ 0.71

(1) In 2010 total estimated proved reserves in our Eagle Ford shale properties contained greater than 15 percent of our total proved reserves expressed on an equivalent basis. During 2010 net production from the Eagle Ford shale was 13.0 Bcf of gas and 0.8 MMBbl of oil, or 17.6 BCFE on an equivalent basis. Our average daily production from the Eagle Ford shale was 35.6 MMcf of gas and 2.1 MBbl of oil, for an average equivalent production rate of 48.3 MMCFE per day. No fields contained 15 percent or greater of our total proved reserves expressed on an equivalent basis in 2009. The SEC rules requiring this disclosure were not effective for the 2008 fiscal year.

Productive Wells

As of December 31, 2010, we had working interests in 1,263 gross (725 net) productive oil wells and 2,861 gross (987 net) productive gas wells. Productive wells are either wells producing in commercial quantities or wells capable of commercial production although currently shut-in. Multiple completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of current production.

Subsequent to year end, we sold certain non-strategic properties in our Rocky Mountain region. Upon closing of this transaction, we divested of 39 gross (31 net) productive oil wells.

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Drilling Activity

All of our drilling activities are conducted on a contract basis with independent drilling contractors. We do not own any drilling equipment. The following table summarizes the number of wells drilled and recompleted in 2010, 2009, and 2008, excluding any wells with only a royalty interest ownership:

	Years Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	191	36.48	103	29.64	221	81.46
Gas	72	16.96	74	18.15	559	205.18
Non-productive	4	1.10	3	1.29	25	13.70
	267	54.54	180	49.08	805	300.34
Exploratory:						
Oil	36	11.52	2	0.42	2	0.40
Gas	83	37.94	18	9.05	10	2.75
Non-productive	1	0.75	5	2.88	1	0.76
	120	50.21	25	12.35	13	3.91
Farmout or non-consent			3		7	
Total	387	104.75	208	61.43	825	304.25

A productive well is an exploratory, development or extension well that is not a dry well. A dry well (hole) is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

As defined in the rules and regulations of the SEC, an exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. A development well is part of a development project, which is defined as the means by which petroleum resources are brought to the status of economically producible. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to the reporting to the appropriate authority that the well has been abandoned.

In addition to the wells drilled and completed in 2010 included in the table above, as of February 18, 2011, we were participating in the drilling of approximately 29 gross wells, all of which are located onshore in the continental United States. We operate nine of these wells with the remaining 20 wells being operated by others. On a net basis, at such date, we were drilling approximately four net operated wells and were participating in approximately three net non-operated wells. With respect to completion activity, at such date, there were approximately 94 wells in which we have an interest that were being completed. We operate 26 of these completion activities on a gross basis, approximately 18 net, and were participating in 68 gross, approximately 11 net, non-operated completion activities. The vast majority, if not all, of these operations relate to the drilling of wells for primary production.

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Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leasehold, fee properties, mineral servitudes, and lease options held by us as of December 31, 2010. Undeveloped acreage includes leasehold interests that may already have been classified as containing proved undeveloped reserves.

	Developed Acres (1)		**Undeveloped Acres (2)**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Arkansas	1,394	163	152	65	1,546	228
Colorado			1,596	860	1,596	860
Kansas			2,240	560	2,240	560
Louisiana	76,404	27,969	13,917	2,694	90,321	30,663
Mississippi	835	199	99,744	41,978	100,579	42,177
Montana	60,311	41,145	328,400	222,550	388,711	263,695
Nevada			197,945	197,945	197,945	197,945
New Mexico	2,361	1,687	1,240	1,022	3,601	2,709
North Dakota	99,119	63,690	180,098	104,583	279,217	168,273
Oklahoma	258,598	82,595	43,586	19,233	302,184	101,828
Pennsylvania	282	282	31,435	27,655	31,717	27,937
Texas	146,648	106,737	624,065	295,817	770,713	402,554
Utah			2,568	561	2,568	561
Wyoming	61,608	28,237	245,194	132,560	306,802	160,797
	707,560	352,704	1,772,180	1,048,083	2,479,740	1,400,787
Louisiana Fee Properties	10,499	10,499	14,415	14,415	24,914	24,914
Louisiana Mineral Servitudes	7,426	4,217	4,769	4,407	12,195	8,624
	17,925	14,716	19,184	18,822	37,109	33,538
Total(3)	725,485	367,420	1,791,364	1,066,905	2,516,849	1,434,325

(1) Developed acreage is acreage assigned to producing wells for the state approved spacing unit of the producing formation. Our developed acreage that includes multiple formations with different well spacing requirements may be considered undeveloped for certain formations, but have only been included as developed acreage in the presentation above.

(2) Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether such acreage contains estimated reserves.

(3) Subsequent to December 31, 2010, we divested certain non-strategic properties, which included leases covering approximately 5,281 and 4,623 gross and net developed acres, respectively, and 6,859 and 5,092 gross and net undeveloped acres, respectively.

Delivery Commitments

During 2010, we entered into natural gas gathering through-put commitments with various parties that require us to deliver a fixed determinable quantity of product. We have an aggregate minimum commitment to deliver 607 Bcf by the end of 2021. We will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment is projected, we have certain rights to arrange for third party gas to be delivered into the gathering lines and such volume will be counted towards our minimum commitment. We expect to fulfill the delivery commitment with our production from our development of our proved reserves, as well as the development of resources not yet characterized as proved reserves, from our Eagle Ford shale and Haynesville shale resource plays. At the current time, we do not have enough proved developed reserves to offset this contractual liability, but we intend to develop reserves that will exceed the through-put commitment. Therefore, we currently do not expect any shortfalls.

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Major Customers

During 2010, the Company had one customer, Regency Gas Services LLC, individually account for approximately 11 percent of our total oil and gas production revenue. During 2009, the Company had one customer, Teppco Crude Oil LLC, individually account for approximately 12 percent of the Company s total oil and gas production revenue. During 2008, no customer individually accounted for ten percent or more of our total oil and gas production revenue.

Employees and Office Space

As of February 18, 2011, we had 569 full-time employees. None of our employees are subject to a collective bargaining agreement and we consider our relations with our employees to be good. As of December 31, 2010, we leased approximately 76,000 square feet of office space in Denver, Colorado for our executive and administrative offices; approximately 22,000 square feet of office space in Tulsa, Oklahoma; approximately 25,000 square feet in Shreveport, Louisiana; approximately 30,000 square feet in Houston, Texas; approximately 17,000 square feet in Midland, Texas; approximately 34,000 square feet in Billings, Montana; approximately 6,000 square feet in Williston, North Dakota; and approximately 2,000 square feet in Casper, Wyoming.

Title to Properties

Substantially all of our interests are held pursuant to leases from third parties. A title opinion is usually obtained prior to the commencement of initial drilling operations. We have obtained title opinions or have conducted a title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. The majority of our producing properties are subject to mortgages securing indebtedness under our credit facility, royalty interests, liens for current taxes, and other burdens that we believe do not materially interfere with the use of or affect the value of such properties. We typically perform only minimal title investigation before acquiring undeveloped leasehold acreage.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during colder winter months and decrease during warmer summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity has placed increased demand on storage volumes. Demand for crude oil and heating oil is also generally higher in the winter and the summer driving season although oil prices are much more driven by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. The impact of seasonality on crude oil has been somewhat magnified by overall supply and demand economics attributable to the narrow margin of production capacity in excess of existing worldwide demand for crude oil.

Competition

The oil and gas industry is intensely competitive, particularly with respect to acquiring prospective oil and natural gas properties. We believe our leasehold position provides a sound foundation for a solid drilling program and our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, and our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete effectively in our core operating areas. However, we face intense competition from a substantial number of major and independent oil and gas companies, which, in some cases, have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have refining operations, market refined products, own drilling rigs, and generate electricity.

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We also compete with other oil and gas companies in attempting to secure drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells. Consequently, we may face shortages or delays in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may also be affected by future new energy, climate-related, financial, and other policies, legislation, and regulations.

In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other professionals. Throughout the oil and gas industry, the need to attract and retain talented people has grown at a time when the number of talented people available is constrained. We are not insulated from this resource constraint, and we must compete effectively in this market in order to be successful.

Government Regulations

Our business is extensively regulated by numerous federal, state, and local laws and governmental regulations. These laws and regulations may be changed from time to time in response to economic or political conditions, or other developments, and our regulatory burden may increase in the future. Laws and regulations increase our cost of doing business and, consequently, affect our profitability. However, we do not believe that we are affected to a materially greater or lesser extent than others in our industry.

Energy Regulations. Many of the states in which we conduct our operations have adopted laws and regulations governing the exploration for and production of crude oil and natural gas, including laws and regulations requiring permits for the drilling of wells, imposing bonding requirements in order to drill or operate wells, and governing the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to various state conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management (BLM). These leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM may require our operations on federal leases to be suspended or terminated.

In May 2010, the BLM adopted changes to its oil and gas leasing program that require, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, increased public engagement in the development of master leasing and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process. These changes may increase the amount of time and regulatory costs necessary to obtain oil and gas leases administered by the BLM.

Our sales of natural gas are affected by the availability, terms, and cost of natural gas pipeline transportation. The Federal Energy Regulatory Commission (FERC) has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce. The FERC s current regulatory framework generally provides for a competitive and open access market for sales and transportation of natural gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect the sales prices we receive for natural gas production. In addition, the less stringent regulatory approach currently pursued by the FERC and the U.S. Congress may not continue indefinitely.

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Environmental, Health, and Safety Regulations. Our operations are subject to stringent federal, state, and local laws and regulations relating to the protection of the environment and human health and safety. Environmental laws and regulations may require that permits be obtained before drilling commences, restrict the types, quantities, and concentration of various substances that can be released into the environment in connection with drilling and production activities, govern the handling and disposal of waste material, and limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, including areas containing endangered animal species. As a result, these laws and regulations may substantially increase the costs of exploring for, developing, or producing oil and gas and may prevent or delay the commencement or continuation of certain projects. In addition, these laws and regulations may impose substantial clean-up, remediation, and other obligations in the event of any discharges or emissions in violation of these laws and regulations. Further, legislative and regulatory initiatives related to global warming or climate change could have an adverse effect on our operations and the demand for oil and natural gas. See Risk Factors Risks Related to Our Business Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. For additional information about hydraulic fracturing and related regulatory matters, see Risk Factors Risks Related to Our Business Proposed federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Federal and state occupational safety and health laws require us to organize and maintain information about hazardous materials used, released, or produced in our operations. Some of this information must be provided to our employees, state and local governmental authorities, and local citizens. We are also subject to the requirements and reporting framework set forth in the federal workplace standards.

To date we have not experienced any materially adverse effect on our operations from obligations under environmental, health, and safety laws and regulations. We believe that we are in substantial compliance with currently applicable environmental, health, and safety laws and regulations, and that continued compliance with existing requirements would not have a materially adverse impact on us.

Cautionary Information about Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words anticipate, assume, believe, budget, estimate, expect, forecast, intend, plan, project, will, and simila intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-K, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;

- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;

- the possible divestiture or farm-down of, or joint venture relating to, certain properties;
- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- future oil and natural gas production estimates;

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- our outlook on future oil and natural gas prices, well costs, and service costs;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the Management s Discussion and Analysis of Financial Condition and Results of Operations section in Item 7 of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the Risk Factors section in Item 1A of this report, and include such factors as:

- the volatility of oil and natural gas prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow;
- the continued weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital that is required to replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- the imprecise estimations of our actual quantities and present values of proved oil and natural gas reserves;

- the uncertainty in evaluating recoverable reserves and other expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;
- the uncertainties associated with enhanced recovery methods;
- our hedging activities may result in financial losses or may limit the prices that we receive for oil and natural gas sales;
- the inability of one or more of our customers to meet their obligations;
- price declines or unsuccessful exploration efforts result in write-downs of our asset carrying values;
- the impact that lower oil or natural gas prices could have on our ability to borrow under our credit facility;

- the possibility that our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil and natural gas;
- new technologies may cause our current exploration and drilling methods to become obsolete; and
- litigation, environmental matters, the potential impact of government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and that actual results or performance may be materially different from those expressed or implied in the forward-looking statements. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

Available Information

Our internet website address is www.sm-energy.com. We routinely post important information for investors on our website. Within our website s investor relations section we make available free of charge our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. We also make available through our website s corporate governance section our Corporate Governance Guidelines, Code of Business Conduct and Ethics, and the Charters for our Board of Directors Audit Committee, Compensation Committee, Executive Committee, and Nominating and Corporate Governance Committee. Information on our website is not incorporated by reference into this report and should not be considered part of this document.

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Glossary of Oil and Gas Terms

The oil and gas terms defined in this section are used throughout this report. The definitions of the terms developed reserves, exploratory well, field, proved reserves, and undeveloped reserves have been abbreviated from the respective definitions under SEC Rule 4-10(a) of Regulation S-X, as amended effective for fiscal years ending on or after December 31, 2009. The entire definitions of those terms under Rule 4-10(a) of Regulation S-X can be located through the SEC s website at www.sec.gov.

Bbl. One stock tank barrel, or 42 U.S. gallons of liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet, used in reference to natural gas.

BCFE. Billion cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas (including natural gas liquids) to one Bbl of oil.

BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of natural gas (including natural gas liquids) to one Bbl of oil.

Btu. One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Developed reserves. Reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing either oil or natural gas in commercial quantities.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Farmout. An assignment of an interest in a drilling location and related acreage conditioned upon the drilling of a well on that location.

Fee land. The most extensive interest that can be owned in land, including surface and mineral (including oil and natural gas) rights.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding cost. Expressed in dollars per MCFE. Finding cost metrics provide information as to the cost of adding proved reserves from various activities, and are widely utilized within the exploration and production industry, as well as by investors. The information used to calculate these metrics is included in Note 14 Oil and Gas Activities and Note 15 Disclosures about Oil and Gas Producing Activities of the Notes to Consolidated Financial Statements included in this report. It should be noted that finding cost metrics have limitations. For example, exploration efforts related to a particular set of proved reserve additions may extend over several years. As a result, the exploration costs incurred in earlier periods are not included in the amount of exploration costs incurred during the period in which that set of proved reserves is added. In addition, consistent with industry practice, future capital costs to develop proved undeveloped reserves are not included in costs incurred. Since the additional development costs that will need to be incurred in the future before the proved undeveloped reserves are ultimately produced are not included in the amount of costs incurred during the period in which those reserves

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were added, those development costs in future periods will be reflected in the costs associated with adding a different set of reserves. The calculations of various finding cost metrics are explained below.

Finding cost Drilling, excluding revisions. Calculated by dividing the amount of costs incurred for development and exploration activities, by the amount of estimated net proved reserves added through discoveries, extensions, and infill drilling, during the same period.

Finding cost Drilling, including revisions. Calculated by dividing the amount of costs incurred for development and exploration activities, by the amount of estimated net proved reserves added through discoveries, extensions, and infill drilling, and revisions of previous estimates during the same period.

Finding cost Drilling and acquisitions, excluding revisions. Calculated by dividing the amount of costs incurred for development, exploration, and acquisition of proved properties, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, and acquisitions during the same period.

Finding cost Drilling and acquisitions, including revisions. Calculated by dividing the amount of costs incurred for development, exploration, and acquisition of proved properties, by the amount of estimated net proved reserves added through discoveries, extensions, and infill drilling, revisions of previous estimates, and acquisitions during the same period.

*Finding cost All in, including sales of reserves.*Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates less sales of reserves during the same period.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Gross acre. An acre in which a working interest is owned.

Gross well. A well in which a working interest is owned.

Horizontal wells. Wells which are drilled at angles greater than 70 degrees from vertical.

Lease operating expenses. The expenses incurred in the lifting of oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition, drilling, or completion costs.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MBOE. One thousand BOE.

MMBOE. One million BOE.

Mcf. One thousand cubic feet, used in reference to natural gas.

MCFE. One thousand cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas (including natural gas liquids) to one Bbl of oil.

MMcf. One million cubic feet, used in reference to natural gas.

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MMCFE. One million cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas (including natural gas liquids) to one Bbl of oil.

MMBtu. One million British thermal units.

Net acres or net wells. The sum of our fractional working interests owned in gross acres or gross wells.

Net asset value per share. The result of the fair market value of total assets less total liabilities, divided by the total number of outstanding shares of common stock.

NGLs. The combination of ethane, propane, butane, and natural gasolines that when removed from natural gas become liquid under various levels of higher pressures and lower temperatures.

NYMEX. New York Mercantile Exchange.

PV-10 value. The present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of ten percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period.

Productive well. A well that is producing oil or natural gas or that is capable of commercial production.

Proved reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Recompletion. The completion in an existing wellbore in a formation other than that in which the well has previously been completed.

Reserve life. Expressed in years, represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.

Reserve replacement. Reserve replacement metrics are used as indicators of a company s ability to replenish annual production volumes and grow its reserves, and provide information related to how successful a company is at growing its proved reserve base. These are believed to be useful non-GAAP measures that are widely utilized within the exploration and production industry, as well as by investors. They are easily calculable metrics, and the information used to calculate these metrics is included in Note 14 Disclosures about Oil and Gas Producing Activities of the Notes to Consolidated Financial Statements included in this report. It should be noted that reserve replacement metrics have limitations. They are limited because they typically vary widely based on the extent and timing of new discoveries and property acquisitions. Their predictive and comparative value is also limited for the same reasons. In addition, since the metrics do not embed the cost or timing of future production of new reserves, they cannot be used as a measure of value creation. The calculations of various reserve replacement metrics are explained below.

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*Reserve replacement Drilling, excluding revisions.*Calculated as a numerator comprised of the sum of reserve extensions and discoveries and infill reserves in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity.

*Reserve replacement Drilling, including revisions.*Calculated as a numerator comprised of the sum of reserve extensions, discoveries, and infill reserves, and revisions and previous estimates in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity.

Reserve replacement Drilling and acquisitions, excluding revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions and discoveries and infill reserves in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities.

Reserve replacement Drilling and acquisitions, including revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions, discoveries, and infill reserves, and revisions and previous estimates in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities.

*Reserve replacement percentage All in, excluding sales of reserves.*The sum of reserve extensions and discoveries, infill drilling, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.

*Reserve replacement percentage All in, including sales of reserves.*The sum of sales of reserves, infill drilling, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Resource play. A term used to describe an accumulation of oil and/or natural gas resources known to exist over a large areal expanse, which when compared to a conventional play typically has a lower expected geological and/or commercial development risk.

Royalty. The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from oil and natural gas produced and sold unencumbered by expenses relating to the drilling, completing, and operating of the affected well.

Royalty interest. An interest in an oil and natural gas property entitling the owner to shares of oil and natural gas production free of costs of exploration, development, and production operations.

Seismic. An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape, and depth of subsurface rock formations.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

Standardized measure of discounted future net cash flows. The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year end costs, and statutory tax rates, and a ten percent annual discount rate. The information for this calculation is included in the note regarding disclosures about oil and gas producing activities contained in the Notes to Consolidated Financial Statements included in this report.

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Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains estimated net proved reserves.

Undeveloped reserves. Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Working interest. The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production, sales, and costs.

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ITEM 1A. RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in SM Energy.

Risks Related to Our Business

Oil and natural gas prices are volatile, and declines in prices adversely affect our profitability, financial condition, cash flows, access to capital, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and natural gas properties depend heavily on the prices we receive for oil and natural gas sales. Oil and natural gas prices also affect our cash flows available for capital expenditures and other items, our borrowing capacity, and the amount and value of our oil and natural gas reserves. For example, the amount of our borrowing base under our credit facility is subject to periodic redeterminations based on oil and natural gas prices specified by our bank group at the time of redetermination. In addition, we may have oil and natural gas property impairments or downward revisions of estimates of proved reserves if prices fall significantly.

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

- global and domestic supplies of oil and natural gas, and the productive capacity of the industry as a whole;
- the level of consumer demand for oil and natural gas;
- overall global and domestic economic conditions;
- weather conditions;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities in regional or localized areas that may affect the realized price for oil, NGLs, or natural gas;

- the price and level of foreign imports of crude oil, refined petroleum products, and liquefied natural gas;

- the price and availability of alternative fuels;

- technological advances affecting energy consumption;

- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

- political instability or armed conflict in oil or natural gas producing regions;

- strengthening and weakening of the U.S. dollar relative to other currencies; and

- governmental regulations and taxes.

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 or 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 have a materially adverse effect on us.

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Continued weakness in economic conditions or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

U.S. and global economies and financial systems have recently experienced turmoil and upheaval characterized by extreme volatility and declines in prices of securities, diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse, or sale of financial institutions, increased levels of unemployment, and an unprecedented level of intervention by the U.S. federal government and other governments. Although some portions of the economy appear to have stabilized and there have been signs of the beginning of recovery, the extent and timing of a recovery, and whether it can be sustained, are uncertain. Continued weakness in the U.S. or other large economies could materially adversely affect our business and financial condition. For example:

- the demand for oil and natural gas in the U.S. has declined and may remain at low levels or further decline if economic conditions remain weak, and continue to negatively impact our revenues, margins, profitability, operating cash flows, liquidity, and financial condition;

- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables;

- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business, including for exploration and/or development of our reserves; and

- our commodity hedging arrangements could become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection.

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

Our future operations depend on our ability to find, develop, or acquire oil and natural gas reserves that are economically producible. Our properties produce oil and natural gas at a declining rate over time. In order to maintain current production rates, we must locate and develop or acquire new oil and natural gas reserves to replace those being depleted by production. In addition, competition for the acquisition of producing oil and natural gas properties is intense and many of our competitors have financial, technical, human, and other resources needed to evaluate and integrate acquisitions that are substantially greater than those available to us. Therefore, we may not be able to acquire oil and natural gas properties that contain economically producible reserves, or we may not be able to acquire such properties at prices acceptable to us. Without successful drilling or acquisition activities, our reserves, production, and revenues will decline over time.

Substantial capital is required to replace our reserves.

We must make substantial capital expenditures to find, acquire, develop, and produce oil and natural gas reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, prices received for oil and natural gas sales, our success in locating and developing and acquiring new reserves, and the orderly functioning of credit and capital markets. If oil or natural gas prices decrease or if we encounter operating difficulties that result in our cash flows from operations being less than expected, we must reduce our capital expenditures unless we can raise additional funds through debt or equity financing or the divestment of assets. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms, and the proceeds offered to us for potential divestitures may not always be of acceptable value to us.

If our revenues decrease due to lower oil, natural gas, or NGL prices, decreased production, or other reasons, and if we cannot obtain capital through our credit facility, other acceptable debt or equity financing arrangements, or through the sale of assets, our ability to execute development plans, replace our reserves, maintain our acreage, or maintain production levels could be greatly limited.

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

We face intense competition from major oil and gas companies, independent oil and natural gas exploration and production companies, financial buyers, and institutional and individual investors who seek oil and natural gas property investments throughout the world, as well as the equipment, expertise, labor, and materials required to operate oil and natural gas properties. Many of our competitors have financial, technical, and other resources vastly exceeding those available to us, and many oil and natural gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for the properties. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We may not be successful in acquiring and developing profitable properties in the face of this competition.

We also compete for human resources. Over the last few years, the need for talented people across all disciplines in the industry has grown, while the number of talented people available has been constrained.

The actual quantities and present values of our proved oil and natural gas reserves may be less than we have estimated.

This report and other SEC filings by us contain estimates of our proved oil and natural gas reserves and the estimated future net revenues from those reserves. These estimates are based on various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, timing of operations, and availability of funds. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. These estimates are dependent on many variables, and therefore changes often occur as these variables evolve. Therefore, these estimates are inherently imprecise.

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 affect the estimated quantities of and present values related to proved reserves disclosed by us, 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.

As of December 31, 2010, approximately 30 percent, or 297.2 BCFE, of our estimated proved reserves were proved undeveloped, and approximately eight percent, or 75.4 BCFE, were proved developed non-producing. Estimates of proved undeveloped reserves and proved developed non-producing reserves are nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. In order to develop our proved undeveloped reserves, we estimate approximately $699 million of capital expenditures would be required. Production revenues from proved developed non-producing reserves will not be realized until sometime in the future and after some investment of capital. In order to bring production on-line for our proved developed non-producing reserves, we estimate capital expenditures of approximately $43 million will be deployed in future years. Although we have estimated our reserves and the costs associated with these reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled and actual results may not occur as estimated. The balance of our currently anticipated capital expenditures for 2011 is directed towards projects that are not yet classified within the construct of proved reserves as defined by Regulation S-X promulgated by the SEC.

You should not assume that the PV-10 value and standardized measure of discounted future net cash flows included in this report represent the current market value of our estimated proved oil and natural gas

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reserves. Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. For example, values of our reserves as of December 31, 2010, were estimated using a calculated 12-month average sales price of $4.38 per MMBtu of natural gas (NYMEX Henry Hub spot price) and $79.43 per Bbl of oil (NYMEX West Texas Intermediate spot price). We then adjust these base prices to reflect appropriate basis, quality, and location differentials over that period in estimating our proved reserves. During 2010, our monthly average realized natural gas prices, excluding the effect of hedging, were as high as $6.43 per Mcf and as low as $4.37 per Mcf. For the same period, our monthly average realized oil prices before hedging were as high as $83.40 per Bbl and as low as $66.59 per Bbl. Many other factors will affect actual future net cash flows, including:

- amount and timing of actual production;
- supply and demand for oil and natural gas;
- curtailments or increases in consumption by oil purchasers and natural gas pipelines; and
- changes in government regulations or taxes.

The timing of production from oil and natural gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing PV-10 values. In addition, the ten percent discount factor required by the SEC to be used to calculate PV-10 values for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates, costs of capital, and other risks to which our business and the oil and natural gas industry in general are subject.

Reserve estimates as of December 31, 2010 and 2009 have been prepared under the SEC s new rules for oil and gas reporting that were effective for fiscal years ending on or after December 31, 2009. These new rules require SEC reporting companies to prepare their reserve estimates using, among other things, revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing, instead of the prior requirement to use pricing at the end of the period. The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules in the near future. The interpretation of these rules and their applicability in different situations remains unclear in many respects. Changing interpretations of the rules or disagreements with our interpretations could result in revisions to our reserve estimates, which could be significant.

Our property acquisitions may not be worth what we paid due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include exploration potential, future oil and natural gas prices, operating costs, and potential environmental and other liabilities. These assessments are not precise and their accuracy is inherently uncertain.

In connection with our acquisitions, we typically perform a customary review of the acquired properties that will not necessarily reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties.

In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such acquisitions may be limited.

Integrating acquired properties and businesses involves a number of other special risks, including the risk that management may be distracted from normal business concerns by the need to integrate operations and systems as well as retain and assimilate additional employees. Therefore, we may not be able to realize all of the anticipated benefits of our acquisitions.

Exploration and development drilling may not result in commercially producible reserves.

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

- unexpected drilling conditions;
- title problems;
- pressure or geologic irregularities in formations;
- equipment failures or accidents;
- hurricanes or other adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, and supplies.

The prevailing prices of oil and natural gas affect the cost of and the demand for drilling rigs, completion and production equipment, and other related services. However, changes in costs may not occur simultaneously with corresponding changes in commodity prices. The availability of drilling rigs can vary significantly from region to region at any particular time. Although 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. In addition, the recent economic and financial downturn has adversely affected the financial condition of some drilling contractors, which may constrain the availability of drilling services in some areas.

Another significant risk inherent in our drilling plans is the need to obtain 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 materially adverse effect on our ability to explore on or develop our properties.

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

Drilling results in our newer shale plays, such as the Eagle Ford and Haynesville shales, may be more uncertain than in shale plays that are more developed and have longer established production histories. For

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example, our experience with horizontal drilling in these shales, as well as the industry s drilling and production history, is more limited than in the Woodford shale play, and we have less information with respect to the ultimate recoverable reserves and the production decline rates in these shales than we have in other areas in which we operate. Completion techniques that have proven to be successful in other shale formations to maximize recoveries are being used in the early development of these new shales; however, we can provide no assurance of the ultimate success of these drilling and completion techniques. As a result, we may face significant opposition to our operations in that area that may make it difficult to obtain permits and other needed authorizations to operate or otherwise make operating more costly or difficult than operating elsewhere.

In addition, a significant part of our strategy involves increasing our inventory of drilling locations. Such multi-year drilling inventories can be more susceptible to long-term horizon uncertainties that could materially alter the occurrence or timing of actual drilling. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled, although we have the present intent to do so, or if we will be able to produce oil or natural gas from these or any other potential drilling locations.

Our future drilling activities may not be successful. Our overall drilling success rate or our drilling success rate within a particular area may decline. In addition, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.

Part of our strategy involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Many of our operations involve utilizing the latest drilling and completion techniques as developed by ourselves and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore, and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations, and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and takeaway capacity, and/or natural gas and oil prices decline, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.

We inject water into formations on some of our properties to increase the production of oil and natural gas. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. In addition, if proposed legislation and regulatory initiatives relating to hydraulic fracturing become law, the cost of some of these enhanced recovery methods could increase substantially.

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Our hedging activities may result in financial losses or may limit the prices that we receive for oil and natural gas sales.

To manage our exposure to price risks in the sale of our oil and natural gas production, we enter into commodity price risk management arrangements periodically with respect to a portion of our current or future production. We have hedged a portion of anticipated future production from our currently producing properties using zero-cost collars and swaps. As of December 31, 2010, we were in a net accrued liability position of approximately $52.3 million with respect to our oil and natural gas hedging activities. These activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;

- one or more counterparties to our hedge contracts default on their contractual obligations; or

- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement.

The risk of one or more counterparties defaulting on their obligations is heightened by the recent global and domestic economic and financial downturn affecting many banks and other financial institutions, including our counterparties and their affiliates. These circumstances may adversely affect the ability of our counterparties to meet their obligations to us pursuant to hedge transactions, which could reduce our revenues and cash flows from realized hedge settlements. As a result, our financial condition, results of operations, and cash flows could be materially affected in an adverse way if our counterparties default on their contractual obligations under our hedge contracts.

In addition, commodity price hedging may limit the prices that we receive for our oil and natural gas sales if oil or natural gas prices rise substantially over the price established by the hedge. Some of our hedging transactions use derivative instruments that may involve basis risk. Basis risk in a hedging contract can occur when the change in the index upon which the hedge is based does not correlate well to the change in the index upon which the hedged production is valued, thereby making the hedge less effective. For example, a change in the NYMEX price used for hedging certain volumes of production may not correlate exactly to the change in the regional price used for the sale of that production.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest billings to third parties in the oil and natural gas industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by various economic and other conditions, including the recent global and domestic economic and financial downturn.

Future oil and natural gas price declines or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our oil and natural gas properties. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our oil and natural gas properties, on a field basis, cannot exceed the estimated undiscounted future net cash flows of that field. If net capitalized costs exceed undiscounted future net revenues, we generally must write down the costs of each such field to the estimated discounted future net cash flows of that field. Unproved properties are evaluated at the lower of cost or fair market value. As a result of significant oil and natural gas price declines in the second half of 2008, we incurred impairment of proved property write-downs, impairment of unproved properties, and goodwill impairment totaling $302.2 million, $39.0 million, and $9.5 million, respectively, during 2008. In addition, we incurred impairment of proved property write-downs and

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impairment of unproved properties totaling $174.8 million and $45.4 million, respectively, during 2009, and $6.1 million and $2.0 million, respectively, during 2010. Significant further declines in oil or natural gas prices in the future or unsuccessful exploration efforts could cause further impairment write-downs of capitalized costs.

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

Lower oil or natural gas prices could limit our ability to borrow under our credit facility.

Our credit facility has a maximum commitment amount of $678.0 million, subject to a borrowing base that the lenders periodically redetermine based on the bank group s assessment of the value of our oil and natural gas properties, which in turn is based in part on oil and natural gas prices. The current borrowing base under our credit facility is $1.0 billion. Pursuant to the terms of our credit facility, the borrowing base was reduced from the previous $1.1 billion borrowing base upon the issuance of our 6.625% Senior Notes, which occurred on February 7, 2011. 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.

Our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt.

As of December 31, 2010, we had $275.7 million, net of debt discount, of total long-term senior unsecured debt outstanding under our 3.50% Senior Convertible Notes due 2027 (the 3.50% Senior Convertible Notes), and $48.0 million of secured debt outstanding under our credit facility. We have a single letter of credit outstanding under our credit facility, in the amount of $483,000 as of February 18, 2011, which reduces the amount available under the commitment amount on a dollar-for-dollar basis. As of February 18, 2011, we had no outstanding borrowings under our credit facility, resulting in $677.5 million of available debt capacity under our credit facility assuming the borrowing conditions of this facility were met, and an additional $350.0 million of long-term senior unsecured debt outstanding related to our 6.625% Senior Notes that we issued on February 7, 2011. Our long-term debt represented 21 percent of our total book capitalization as of December 31, 2010. Adjusting for our 6.625% Senior Notes, our long-term debt would have represented 34 percent of our total book capitalization as of December 31, 2010.

Our amount of debt could have important consequences for our operations, including:

- making it more difficult for us to obtain additional financing in the future for our operations and potential acquisitions, working capital requirements, capital expenditures, debt service, or other general corporate requirements;

- requiring us to dedicate a substantial portion of our cash flows from operations to the repayment of our debt and the service of interest costs associated with our debt, rather than to productive investments;

- limiting our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making acquisitions, and paying dividends;

- placing us at a competitive disadvantage compared to our competitors that have less debt; and

- making us more vulnerable in the event of adverse economic or industry conditions or a downturn in our business.

Our ability to make payments on our debt and to refinance our debt and fund planned capital expenditures will depend on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory, and other factors that are beyond our control. If our business does

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not generate sufficient cash flow from operations or future sufficient borrowings are not available to us under our credit facility or from other sources, we might not be able to service our debt or fund our other liquidity needs. If we are unable to service our debt, due to inadequate liquidity or otherwise, we may have to delay or cancel acquisitions, defer capital expenditures, sell equity securities, sell assets, or restructure or refinance our debt. We might not be able to sell our equity securities, sell our assets, or restructure or refinance our debt on a timely basis or on satisfactory terms or at all. In addition, the terms of our existing or future debt agreements, including our existing and future credit agreements, may prohibit us from pursuing any of these alternatives. Further, changes in the credit ratings of our debt may negatively affect the cost, terms, conditions, and availability of future financing. The indenture under our 3.50% Senior Convertible Notes provides that under certain circumstances we have the option to settle our obligations under these Notes through the issuance of shares of our common stock if we so elect.

Our debt agreements, including the agreement governing our credit facility and the indenture governing the 6.625% Senior Notes, also permit us to incur additional debt in the future, subject to compliance with restrictive covenants under those agreements. In addition, entities we may acquire in the future could have significant amounts of debt outstanding which we could be required to assume, and in some cases accelerate repayment thereof, in connection with the acquisition, or we may incur our own significant indebtedness to consummate an acquisition.

As discussed above, our credit facility is subject to periodic borrowing base redeterminations. We could be forced to repay a portion of our bank borrowings in the event of a downward redetermination of our borrowing base, and we may not have sufficient funds to make such repayment at that time. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowing base or arrange new financing, we may be forced to sell significant assets.

The agreements governing our debt contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the acceleration of our debt.

Our debt agreements contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under our credit facility is subject to compliance with certain financial covenants, including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest, taxes, depreciation, and amortization of no greater than 3.5 to 1.0, and (ii) maintenance of a current ratio of no less than 1.0 to 1.0, each as defined in our credit facility. Our credit facility also requires us to comply with certain financial covenants, including requirements that we maintain certain levels of stockholders   equity and limit our annual dividend rate to no more than $0.25 per share. These restrictions on our ability to operate our business could seriously harm our business by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

The indenture governing the 6.625% Senior Notes also contains covenants that, among other things, limit our ability and the ability, of our subsidiaries to:

- incur additional debt;
- make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem, or retire capital stock;

- sell assets, including capital stock of our subsidiaries;
- restrict dividends or other payments of our subsidiaries;
- create liens that secure debt;
- enter into transactions with affiliates; and

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- merge or consolidate with another company.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

We are subject to operating and environmental risks and hazards that could result in substantial losses.

Oil and natural gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas, or well fluids, fires, adverse weather such as hurricanes in the South Texas & Gulf Coast region, freezing conditions in the Williston Basin of our Rocky Mountain region, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas, and other environmental risks and hazards. If any of these types of events occurs, we could sustain substantial losses.

Under certain limited 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 substantial 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.

We maintain insurance against some, but not all, of these potential risks and losses. We have significant but limited coverage for sudden environmental damages. We do not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damages or insurance coverage for environmental damage that occurs over time is available at a reasonable cost. In addition, pollution and environmental risks generally are not fully insurable. Further, we may elect not to obtain other insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks to which we are subject. Accordingly, we may be subject to liability or may lose substantial assets in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, we could suffer a material loss.

Following the severe Atlantic hurricanes in 2004, 2005, and 2008, the insurance markets suffered significant losses. As a result, insurance coverage for wind storms has become substantially more expensive, and future availability and costs of coverage are uncertain.

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

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

Governmental authorities regulate various aspects of oil and natural gas drilling and production, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of interests in oil and natural gas properties, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging and abandonment standards, and restoration. Under certain circumstances, federal authorities may require any of our ongoing or planned operations on federal leases to be delayed, suspended, or terminated. Any such delay, suspension, or termination could have a materially adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies.

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Under existing or future environmental laws and regulations, we could face significant liability to governmental authorities and third parties, including joint and several as well as strict liability, for discharges of oil, natural gas, or other pollutants into the air, soil, or water, and we could be required to spend substantial amounts on investigations, litigation, and remediation. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a materially adverse effect on us.

Proposed federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. We routinely utilize hydraulic fracturing techniques in many of our reservoirs, and our Eagle Ford, Haynesville, and Woodford shale programs utilize or contemplate the utilization of hydraulic fracturing. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the U.S. Environmental Protection Agency, or the EPA, recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act s Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing operations. For example, Pennsylvania, Colorado, and Wyoming have each adopted a variety of well construction, set back, and disclosure regulations limiting how fracturing can be performed and requiring various degrees of chemical disclosure. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Proposed legislation to eliminate or reduce certain federal income tax incentives and deductions available to oil and gas exploration and production companies could, if enacted into law, have a material adverse effect on our results of operations and cash flows.

President Obama s budget proposal for the fiscal year 2011 recommended the elimination of certain key U.S. federal income tax preferences currently available to coal, oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities, and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for, or development of, oil or gas within the United States.

It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the Budget Proposal or any other similar change in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and gas exploration and production.

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Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases 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 greenhouse gases under existing provisions of the Clean Air Act, or CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or 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, NGLs, and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases 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 greenhouse gases 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 and results of operations.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade execution requirements in connection with its derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the 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 new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Our ability to sell oil, natural gas and NGLs, and/or receive market prices for our production, may be adversely affected by constraints on gathering systems, processing facilities, pipelines and other transportation systems owned or operated by others or by other interruptions.

The marketability of our oil, natural gas and NGL production depends in part on the availability, proximity, and capacity of gathering systems, processing facilities and pipeline and other transportation systems owned or operated by third parties. The lack of available capacity in these systems and facilities can result in the shutting-in of producing wells, the delay or discontinuance of development plans for our properties, or lower price realizations. Although we have some contractual control over the processing and transportation of our production, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, process and transport oil, natural gas and NGLs.

In particular, if drilling in the Eagle Ford, Haynesville, Granite Wash, and Marcellus plays continues to be successful, the amount of crude oil, NGLs and natural gas being produced by us and others could exceed the capacity of, and result in strains on, the various gathering, and transportation systems, pipelines, processing facilities, and other infrastructure available in these areas. It will be necessary for additional infrastructure, pipelines, gathering, and transportation systems and processing facilities to be expanded, built or developed to accommodate anticipated production from these areas. Because of the current economic climate, certain processing or pipeline and other gathering or transportation projects that might be, or are being, considered for these areas may not be developed timely or at all due to lack of financing or other constraints. In addition, capital and other constraints could limit our ability to build or access intrastate gathering and transportation systems necessary to transport our production to interstate pipelines or other points of sale or delivery. In such event, we might have to delay or discontinue development activities or shut in our wells to wait for sufficient infrastructure development or capacity expansion and/or sell production at significantly lower prices than those quoted on NYMEX, which would adversely affect our results of operations and cash flows.

A portion of our production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline, gathering, processing or transportation system access or capacity, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flows and results of operations.

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to

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implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly, which may result in losses for investors.

From January 1, 2010 to February 18, 2011, the closing daily sale price of our common stock as reported by the New York Stock Exchange ranged from a low of $31.64 per share in February 2010 to a high of $66.39 per share in February 2011. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- changes in oil or natural gas prices;
- variations in quarterly drilling, recompletions, acquisitions, and operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- future sales of our common stock; and
- changes in the national and global economic outlook.

We may not meet the expectations of our stockholders and/or of securities analysts at some time in the future, and our stock price could decline as a result.

Our certificate of incorporation and by-laws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment.

Our certificate of incorporation and by-laws contain provisions that may have the effect of delaying or preventing a change of control. These provisions, among other things, provide for non-cumulative voting in the election of members of the Board of Directors and impose procedural requirements on stockholders who wish to make nominations for the election of directors or propose other actions at stockholder meetings. These provisions, alone or in combination with each other and with the shareholder rights plan described below, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

Under our shareholder rights plan, if the Board of Directors determines that the terms of a potential acquisition do not reflect the long-term value of SM Energy, the Board of Directors could allow the holder of each outstanding share of our common stock, other than those held by the potential acquirer, to purchase one additional share of our common stock with a market value of twice the exercise price. This prospective dilution to a potential acquirer would make the acquisition impracticable unless the terms were improved to the satisfaction of the Board of Directors. The existence of the plan may impede a takeover not supported by our Board of Directors, even though such takeover may be desired by a majority of our stockholders or may involve a premium over the prevailing stock price.

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Shares eligible for future sale may cause the market price of our common stock to drop significantly, even if our business is doing well.

The potential for sales of substantial amounts of our common stock in the public market may have a materially adverse effect on our stock price. As of February 18, 2011, 63,335,590 million shares of our common stock were freely tradable without substantial restriction or the requirement of future registration under the Securities Act of 1933. Also as of that date, options to purchase 795,496 shares of our common stock were outstanding, all of which were exercisable. These options are exercisable at prices ranging from $7.97 to $20.87 per share. In addition, restricted stock units (RSUs) providing for the issuance of up to a total of 335,809 shares of our common stock and 1,381,929 performance share awards (PSAs) were outstanding. The PSAs represent the right to receive, upon settlement of the PSAs after the completion of a three-year performance period, a number of shares of our common stock that may be from zero to two times the number of PSAs granted, depending on the extent to which the underlying performance criteria have been achieved and the extent to which the PSAs have vested. As of February 18, 2011, there were 63,435,434 shares of our common stock outstanding, which is net of 102,635 treasury shares.

We may not always pay dividends on our common stock.

Payment of future dividends remains at the discretion of the Board of Directors, and will continue to depend on our earnings, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to covenants in our credit facility, including a covenant regarding the level of our current ratio of current assets to current liabilities and a limit on the annual dividend rate that we may pay to no more than $0.25 per share, and to covenants in the indenture for our 6.625% Senior Notes that limit our ability to pay dividends beyond a certain amount. The Board of Directors may determine in the future to reduce the current semi-annual dividend rate of $0.05 per share, or discontinue the payment of dividends altogether.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

SM Energy has no unresolved comments from the SEC staff regarding its periodic or current reports under the Securities Exchange Act of 1934.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the date of this report no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows.

We note that approximately 22,000 acres of our approximately 250,000 net acres in the Eagle Ford shale play in South Texas are the subject of a lawsuit captioned *W.H. Sutton, et al. vs. St. Mary Land & Exploration Co., et al.* instituted in the District Court of Webb County in and for the 49th Judicial District of Texas on May 13, 2010. The plaintiffs claim an aggregate overriding royalty interest of 7.46875% in production attributable to a 1966 oil, gas and mineral lease, and that such overriding royalty interest attaches to subsequent leases currently affecting the acreage that is the subject of the lawsuit, which had been released from the 1966 lease. The plaintiffs seek to quiet title to their claimed overriding royalty interest and the recovery of unpaid overriding royalty interest proceeds allegedly due. We believe that the claimed overriding royalty interest has been terminated under the governing agreements and the applicable law, and filed an answer denying the plaintiffs claims. Both parties filed motions for summary judgment, and on February 8, 2011, the District Court issued an order granting plaintiffs motion for summary judgment and denying our motion for summary judgment. The order granting plaintiffs motion for summary judgment did not award damages but reserved such determination for final order. We believe that the summary judgment is incorrect under the governing agreements and applicable law, and intend to appeal. On February 16, 2011, the plaintiffs filed a motion requesting that the court enter final judgment in favor of plaintiffs and requesting the award of damages of approximately $6.6 million, including attorneys fees of approximately $1.9 million.

We believe this lawsuit is entirely without merit and will continue to vigorously contest this litigation. However, we cannot predict the ultimate outcome of this lawsuit. If the plaintiffs were to ultimately prevail, the overriding royalty interest would have the effect of reducing our net revenue interest in the affected acreage, which would negatively impact our economics in this portion of our acreage, but we do not believe would have a material adverse effect upon our financial condition, results of operations or cash flows, taken as a whole. For a more detailed discussion of our Eagle Ford shale play, see Core Operational Areas, South Texas & Gulf Coast Region in Part I, Items 1. and 2. of this report.

ITEM 4. [REMOVED AND RESERVED]

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the names, ages and positions held by SM Energy s executive officers. The age of the executive officers is as of February 18, 2011.

Name	**Age**	**Position**
Anthony J. Best	61	Chief Executive Officer and President
Javan D. Ottoson	52	Executive Vice President and Chief Operating Officer
A. Wade Pursell	45	Executive Vice President and Chief Financial Officer
David W. Copeland	54	Senior Vice President and General Counsel
Gregory T. Leyendecker	53	Senior Vice President and Regional Manager
Mark D. Mueller	46	Senior Vice President and Regional Manager
Lehman E. Newton, III	55	Senior Vice President and Regional Manager
Stephen C. Pugh	52	Senior Vice President and Regional Manager
Paul M. Veatch	44	Senior Vice President and Regional Manager
Dennis A. Zubieta	44	Vice President Engineering and Evaluation
Mark T. Solomon	42	Controller

Anthony J. Best. Mr. Best joined the Company in June 2006 as President and Chief Operating Officer. In December 2006, Mr. Best relinquished his position as Chief Operating Officer when Javan D. Ottoson was elected to that office. Mr. Best was elected Chief Executive Officer of the Company in February 2007. From November 2005 to June 2006, Mr. Best was developing a business plan and securing capital commitments for a new exploration and production entity. From 2003 to October 2005, Mr. Best was President and Chief Executive Officer of Pure Resources, Inc., an independent oil and natural gas exploration and production company that was a subsidiary of Unocal, where he managed all of Unocal s onshore U.S. assets. From 2000 to 2002, Mr. Best had an oil and gas consulting practice, working with various energy firms. From 1979 to 2000, Mr. Best was with ARCO in a variety of positions, including serving as President ARCO Latin America, President ARCO Permian, Field Manager for Prudhoe Bay and VP External Affairs for ARCO Alaska. Mr. Best has over 30 years of experience in the energy industry.

Javan D. Ottoson. Mr. Ottoson joined the Company in December 2006 as Executive Vice President and Chief Operating Officer. Mr. Ottoson has been in the energy industry for over 25 years. From April 2006 until he joined the Company in December 2006, Mr. Ottoson was Senior Vice President Drilling and Engineering at Energy Partners, Ltd., an independent oil and natural gas exploration and production company, where his responsibilities included overseeing all aspects of its drilling and engineering functions. Mr. Ottoson managed Permian Basin assets for Pure Resources, Inc., a Unocal subsidiary, and its successor owner, Chevron, from July 2003 to April 2006. From April 2000 to July 2003, Mr. Ottoson owned and operated a homebuilding company in Colorado and ran his family farm. Prior to 2000 Mr. Ottoson worked for ARCO in a variety of management and operational roles, including serving as President of ARCO China, Commercial Director of ARCO United Kingdom, and Vice President of Operations and Development, ARCO Permian.

A. Wade Pursell. Mr. Pursell joined the Company in September 2008 as Executive Vice President and Chief Financial Officer. Mr. Pursell was Executive Vice President and Chief Financial Officer for Helix Energy Solutions Group, Inc., a global provider of life-of-field services and development solutions to offshore energy producers and an oil and gas producer, from February 2007 to September 2008. From October 2000 to February 2007, he was Senior Vice President and Chief Financial Officer of Helix. He joined Helix in May 1997, as Vice President Finance and Chief Accounting Officer. From 1988 through May 1997, Mr. Pursell was with Arthur Andersen LLP, serving lastly as an Experienced Manager specializing in the offshore services industry. Mr. Pursell has over 24 years of experience in the energy industry.

David W. Copeland. Mr. Copeland joined the Company in January 2011 as Senior Vice President and General Counsel. Mr. Copeland has over 28 years of experience in the legal profession, including over 19 years as internal counsel for various energy companies. Prior to joining the Company, he served at Concho Resources Inc., in Midland, Texas, as its Vice President, General Counsel and Secretary from April 2004 through November 5,

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2009, and then as its Senior Counsel through December 31, 2010. From August 1997 through March 2004, Mr. Copeland served as an executive officer and general counsel of two energy companies he co-founded in Midland, Texas with others. Mr. Copeland started his career in 1982 with the Stubbeman, McRae, Sealy, Laughlin & Browder law firm in Midland, Texas.

Gregory T. Leyendecker. Mr. Leyendecker was appointed Senior Vice President and Regional Manager in May 2010. From July 2007 to May 2010, he served as Vice President and Regional Manager. Mr. Leyendecker joined the Company in December 2006 as Operations Manager for the South Texas & Gulf Coast Region in Houston, Texas. Mr. Leyendecker has over 28 years in the energy industry, and held various positions with Unocal Corporation, an independent oil and natural gas exploration and production company, from 1980 until its acquisition in 2005. During his career with Unocal, he was the Asset Manager for Unocal Gulf Region USA from 2003 to June 2004 and Production and Reservoir Engineering Technology Manager for Unocal from June 2004 to August 2005. He was appointed Drilling and Workover Manager for the San Joaquin Valley business unit of Chevron, as successor-by-merger of Unocal Corporation, in Bakersfield, California in August 2005, and held this position until January 2006. Immediately prior to joining the Company, Mr. Leyendecker was Vice President of Drilling Management Services from February 2006 to November 2006 for Enventure Global Technology, a provider of solid expandable tubular technology.

Mark D. Mueller. Mr. Mueller joined the Company in September 2007 as Senior Vice President. Mr. Mueller was appointed as the Regional Manager of the Rocky Mountain Region effective January 1, 2008. Mr. Mueller has been in the energy industry for over 24 years. From September 2006 to September 2007, he was Vice President and General Manager at Samson Exploration Ltd., an oil and gas exploration and production company that was a subsidiary of Samson Investment Company, in Calgary, Canada, where his responsibilities included fiscal performance, reserves, and all operational functions of the company. From April 2005 until its sale in August 2006, Mr. Mueller was Vice President and General Manager for Samson Canada Ltd., an oil and gas exploration and production company that was a subsidiary of Samson Investment Company, where he was responsible for all business units and the eventual sale of the company. Mr. Mueller joined Samson Canada Ltd. as Project Manager in May 2003 to build a new basin-centered gas business unit and was Vice President from December 2003 to August 2006. Prior to joining Samson, Mr. Mueller was West Central Alberta Engineering Manager for Northrock Resources Ltd., a Canadian oil and gas company that was a wholly-owned subsidiary of Unocal Corporation, in Calgary, Canada. From 1986 to 2003, Mr. Mueller held positions of increasing responsibility in engineering and management for Unocal throughout North America and Southeast Asia.

Lehman E. Newton, III. Mr. Newton joined the Company in December 2006 as General Manager for the Midland, Texas office, was appointed Vice President and Regional Manager of the Permian region in June 2007, and was appointed Senior Vice President and Regional Manager in May 2010. Mr. Newton has over 33 years of experience in the energy industry. From November 2005 to November 2006, Mr. Newton served as Project Manager for one of Chevron s largest Lower 48 projects. Mr. Newton joined Pure Resources in February 2003 as the Business Development Manager and worked in that capacity until October 2005. Mr. Newton was a founding partner in Westwin Energy, an independent Permian Basin exploration and production company, from June 2000 to January 2003. Prior to that, Mr. Newton spent 21 years with ARCO in various engineering, operations and management roles, including as Asset Manager, ARCO s East Texas operations, Vice President, Business Development, ARCO Permian, and Vice President of Operations and Development, ARCO Permian.

Stephen C. Pugh. Mr. Pugh joined the Company as Senior Vice President and Regional Manager of the ArkLaTex Region in July 2007. Mr. Pugh has over 29 years of experience in the energy industry. Prior to joining the Company, Mr. Pugh was Managing Director for Scotia Waterous, a global leader in oil and gas merger and acquisition advisory services from July 2006 to July 2007. Mr. Pugh was responsible for new business development, managing client relationships and providing merger and acquisition advice to clients in the energy sector. Prior to joining Scotia Waterous, Mr. Pugh had over 17 years of experience in acquisitions and divestitures, operations and engineering with Burlington Resources, and its successor-by-merger, ConocoPhillips. His most recent position with Burlington Resources, Inc. and ConocoPhillips was General Manager, Engineering and Operations Gulf Coast, a position he held from May 2004 to June 2006. Prior to that, he was Vice President Acquisitions and Divestitures for Burlington Resources Canada. He held that position from May 2000

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to May 2004. Mr. Pugh began his career with Superior Oil (subsequently Mobil Oil) in Lafayette, Louisiana, where he worked in production, drilling, and reservoir engineering.

Paul M. Veatch. Mr. Veatch was appointed Senior Vice President and Regional Manager of the Company in March 2006. Mr. Veatch joined the Company in April 2001 as Regional A & D Engineer. He served as the Company s Vice President General Manager, ArkLaTex from August 2004 to March 2006, and Manager of Engineering for the ArkLaTex region from April 2003 to August 2004. Mr. Veatch has over 21 years of experience in the energy industry.

Dennis A. Zubieta. Mr. Zubieta was appointed Vice President Engineering and Evaluation of the Company in August 2008. Mr. Zubieta joined the Company in June 2000 as Corporate A&D Engineer, assumed the role of Reservoir Engineer in February 2003, and was appointed Reservoir Engineering Manager in August 2005. Mr. Zubieta was employed by Burlington Resources from June 1988 to May 2000 in various operations and reservoir engineering capacities. Mr. Zubieta has over 22 years of experience in the energy industry.

Mark T. Solomon. Mr. Solomon was appointed Controller of the Company in January 2007. Mr. Solomon served as the Company s Acting Principal Financial Officer from April 30, 2008, to September 8, 2008, which was during the period of time that the Company s Chief Financial Officer position was vacant. Mr. Solomon joined the Company in 1996. He served as Financial Reporting Manager from February 1999 to September 2002, Assistant Vice President Financial Reporting from September 2002 to May 2006 and Assistant Vice President Assistant Controller from May 2006 to January 2007. Prior to joining the Company, Mr. Solomon was an auditor with Ernst & Young. Mr. Solomon has over 14 years of experience in the energy industry.

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PART II

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

Market Information. SM Energy s common stock is currently traded on the New York Stock Exchange under the ticker symbol SM . The following table presents the range of high and low intraday sales prices per share for the indicated quarterly periods in 2010 and 2009, as reported by the New York Stock Exchange:

Quarter Ended		High		Low
December 31, 2010	$	59.82	$	37.30
September 30, 2010		44.93		33.80
June 30, 2010		49.13		35.29
March 31, 2010		38.18		30.70
December 31, 2009	$	38.05	$	29.80
September 30, 2009		33.62		17.13
June 30, 2009		23.48		12.05
March 31, 2009		24.60		11.21

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PERFORMANCE GRAPH

The following performance graph compares the cumulative return on SM Energy s common stock, not including dividend payments, for the period beginning December 31, 2005, and ending on December 31, 2010, with the cumulative total returns of the Dow Jones U.S. Exploration and Production Board Index, and the Standard & Poor s 500 Stock Index.

COMPARE 5-YEAR CUMULATIVE TOTAL RETURN

The preceding information under the caption Performance Graph shall be deemed to be furnished but not filed with the Securities and Exchange Commission.

Holders. As of February 18, 2011, the number of record holders of SM Energy s common stock was 101. Based on inquiry, management believes that the number of beneficial owners of our common stock is approximately 34,500.

Dividends. SM Energy has paid cash dividends to its stockholders every year since 1940. Annual dividends of $0.05 per share were paid in each of the years 1998 through 2004. Annual dividends of $0.10 per share were paid in 2005 through 2010. We expect that our practice of paying dividends on our common stock will continue, although the payment of future dividends will continue to depend on our earnings, cash flow, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to covenants in our credit facility, including the requirement that we maintain the level of our current ratio of current assets to current liabilities and a limitation of our annual dividend rate to no more than $0.25 per share per year. We are also subject to certain covenants under our 6.625% Senior Notes that limit the payment of dividends on our common stock to $6.5 million in any given calendar year during the eight year term of the notes. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $6.3 million in 2010 and $6.2 million in 2009.

Restricted Shares. SM Energy has no restricted shares outstanding as of December 31, 2010, aside from Rule 144 restrictions on shares held by insiders, shares subject to transfer restrictions under the provisions of the Employee Stock Purchase Plan, and shares issued to members of the Board of Directors under the Equity Incentive Compensation Plan (Equity Plan).

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Securities Authorized for Issuance Under Equity Compensation Plans. SM Energy has the Equity Plan under which options and shares of SM Energy common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. Our stockholders have approved this plan. See Note 7 Compensation Plans in the Notes to Consolidated Financial Statements included in Part IV, Item 15 of this report for further information about the material terms of our equity compensation plans. The following table is a summary of the shares of common stock authorized for issuance under the equity compensation plans as of December 31, 2010:

Plan category	**(a)** **Number of securities to be issued upon exercise of outstanding options, warrants, and rights**		**(b)** **Weighted-average exercise price of outstanding options, warrants, and rights**	**(c)** **Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))**
Equity compensation plans approved by security holders:				
Equity Incentive Compensation Plan				
Stock options and incentive stock options(1)	920,765	$	13.11	
Restricted stock(1)	333,359			
Performance share awards(1)(3)	1,398,248	$	39.48	
Total for Equity Incentive Compensation Plan	2,652,372	$	23.65	2,557,096
Employee Stock Purchase Plan(2)				1,415,327
Equity compensation plans not approved by security holders				
Total for all plans	2,652,372	$	23.65	3,972,423

(1) In May 2006 the stockholders approved the Equity Plan to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, performance shares, performance units, and stock-based awards to key employees, consultants, and members of the Board of Directors of SM Energy or any affiliate of SM Energy. The Equity Plan serves as the successor to the SM Energy Company Stock Option Plan, the SM Energy Company Incentive Stock Option Plan, the SM Energy Company Restricted Stock Plan, and the SM Energy Company Non-Employee Director Stock Compensation Plan (collectively referred to as the Predecessor Plans). All grants of equity are now made under the Equity Plan, and no further grants will be made under the Predecessor Plans. Each outstanding award under a Predecessor Plan immediately prior to the effective date of the Equity Plan continues to be governed solely by the terms and conditions of the instruments evidencing such grants or issuances. Our Board of Directors approved amendments to the Equity Plan in March 2008, 2009, and 2010, and each amended plan was approved by stockholders at the respective annual stockholders meetings. Awards granted in 2010, 2009, and 2008 under the Equity Plan were 540,774, 1,016,931, and 932,767, respectively.

(2) Under the SM Energy Company Employee Stock Purchase Plan (the ESPP), eligible employees may purchase shares of our common stock through payroll deductions of up to 15 percent of their eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the six-month offering period, and shares issued under the ESPP through December 31, 2009, are restricted for a period of 18 months from the date issued. Effective January 1, 2010, shares issued under the ESPP will be restricted for a period six months from the date issued. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. Shares issued under the ESPP totaled 52,948, 86,308, and 45,228 in 2010, 2009, and 2008, respectively.

(3) The PSAs represent the right to receive, upon settlement of the PSAs after the completion of a three-year performance measurement period, a number of shares of our common stock that may be from zero to two times the number of PSAs granted, depending on the extent to which the underlying performance criteria have been achieved and the extent to which the PSAs have vested. The performance criteria for the PSAs are based on a combination of our annualized Total Shareholder Return (TSR) for the performance period and the relative measure of our TSR compared with the TSR of an index comprised of certain peer companies for the performance period. The current outstanding PSAs were granted on July 1, 2010, August 1, 2009, and August 1, 2008, and utilize a three-year performance measurement period, which began on July 1, 2010, 2009, and 2008, respectively. On July 1, 2010, the grant date, the market value per share of our common stock was $40.15. On July 1, 2009, the market value per share of our common stock

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was $21.15, and on the date of grant the market value per share of our common stock was $23.87. On July 1, 2008, the market value per share of our common stock was $62.51, and on the date of grant the market value per share of our common stock was $43.11. The PSAs do not have an exercise price associated with them, but rather the $39.48 price shown in the above table represents the weighted-average per share fair value as of December 31, 2010, which is presented in order to provide additional information regarding the potential dilutive effect of the PSAs as of December 31, 2010, in view of the share price level at the beginning of the performance period, which will be utilized to compute the TSR measurements for determination of the number of shares to be issued upon settlement of the PSAs after completion of the three-year performance measurement period.

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Purchases of Equity Securities By the Issuer and Affiliated Purchasers. The following table provides information about purchases by the Company and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the indicated quarters and year ended December 31, 2010, of shares of the Company s common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

ISSUER PURCHASES OF EQUITY SECURITIES

	Total Number of Shares Purchased(1)	Average Price Paid per Share		Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program(2)
January 1, 2010 March 31, 2010	16,100	$	32.75		3,072,184
April 1, 2010 June 30, 2010	427	$	40.47		3,072,184
July 1, 2010 September 30, 2010	8,794	$	41.42		3,072,184
October 1, 2010 October 31, 2010	91	$	41.35		3,072,184
November 1, 2010 November 30, 2010	87	$	42.42		3,072,184
December 1, 2010 December 31, 2010	21,779	$	54.01		3,072,184
Total October 1, 2010 December 31, 2010	21,957	$	53.92		3,072,184
Total	47,278	$	44.26		3,072,184

(1) All shares purchased in 2010 were to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying restricted stock units delivered under the terms of grants under the Equity Plan.

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, we may repurchase up to 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of SM Energy s credit facility, provisions of our 6.625% Senior Notes, and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, or borrowings under our credit facility. The stock repurchase program may be suspended or discontinued at any time.

The payment of dividends is subject to covenants in our credit facility, including the requirement that we maintain certain levels of stockholders equity and the limitation that does not allow our annual dividend rate may not exceed $0.25 per share. The payment of dividends is also subject to covenants under our 6.625% Senior Notes, including covenants limiting the payment of dividends on our common stock to $6.5 million in the aggregate in any given calendar year during the eight year term of the notes.

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth supplemental selected financial and operating data for SM Energy as of the dates and periods indicated. The financial data for each of the five years presented were derived from the consolidated financial statements of SM Energy. The following data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with SM Energy s consolidated financial statements included in this report.

	Years Ended December 31,				
	2010	2009	2008	2007	2006
	(in thousands, except per share data)				
Total operating revenues	$ 1,092,834	$ 832,201	$ 1,301,301	$ 990,094	$ 787,701
Net income (loss)	$ 196,837	$ (99,370)	$ 87,348	$ 187,098	$ 190,015
Net income (loss) per share:					
Basic	$ 3.13	$ (1.59)	$ 1.40	$ 3.02	$ 3.38
Diluted	$ 3.04	$ (1.59)	$ 1.38	$ 2.90	$ 2.94
Total assets at year end	$ 2,744,321	$ 2,360,936	$ 2,697,247	$ 2,572,942	$ 1,899,097
Long-term debt:					
Line of credit	$ 48,000	$ 188,000	$ 300,000	$ 285,000	$ 334,000
Senior convertible notes, net of debt discount	$ 275,673	$ 266,902	$ 258,713	$ 251,070	$ 99,980
Cash dividends declared and paid per common share	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10

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Supplemental Selected Financial and Operations Data

	Years Ended December 31,				
	2010	2009	2008	2007	2006
	(in thousands, except sales prices, volumes, and per MCFE amounts)				
Balance Sheet Data					
Total working capital (deficit)	$ (227,408)	$ (87,625)	$ 15,193	$ (92,604)	$ 22,870
Total stockholders equity	$ 1,218,526	$ 973,570	$ 1,162,509	$ 902,574	$ 743,374
Weighted-average shares outstanding					
Basic	62,969	62,457	62,243	61,852	56,291
Diluted	64,689	62,457	63,133	64,850	65,962
Reserves					
Oil (MMBbl)	57.4	53.8	51.4	78.8	74.2
Gas (Bcf)	640.0	449.5	557.4	613.5	482.5
BCFE	984.5	772.2	865.5	1,086.5	927.6
Production and Operational:					
Oil and gas production revenues, including hedging	$ 859,753	$ 756,601	$ 1,158,304	$ 936,577	$ 758,913
Oil and gas production expenses	$ 195,075	$ 206,800	$ 271,355	$ 218,208	$ 176,590
DD&A	$ 336,141	$ 304,201	$ 314,330	$ 227,596	$ 154,522
General and administrative	$ 106,663	$			