UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **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

☐ **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 ☒ No ☐

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 ☐ No ☒

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 ☒ No ☐

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 ☒ No ☐

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. ☐

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 ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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

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,

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.

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.

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.

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

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.

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	2008
		(in thousands)	
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.

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.

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 similar expressions are 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.

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

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.

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.

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.

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.

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

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

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

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

- 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.

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.

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

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,

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

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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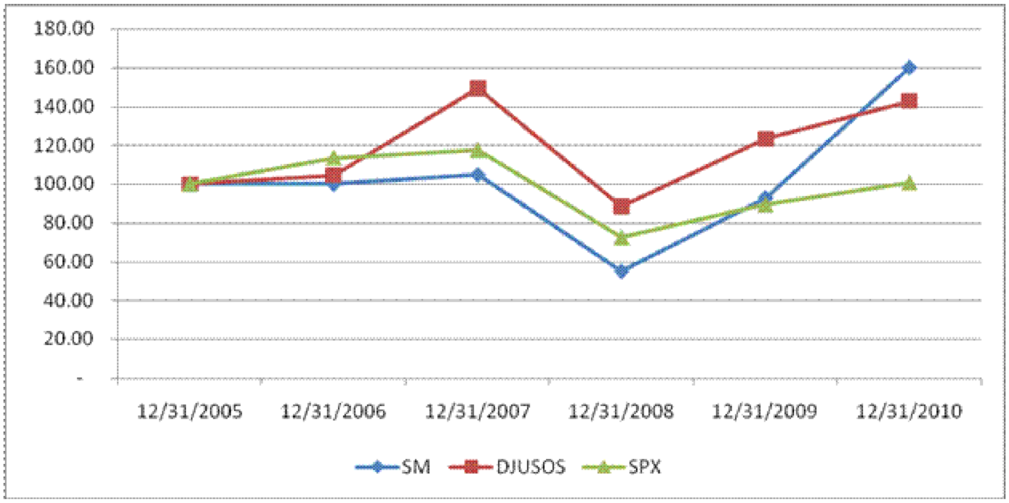
PERFORMANCE GRAPH

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").

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

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.

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.

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

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	$ 76,036	$ 79,503	$ 60,149	$ 38,873
Production Volumes:					
Oil (MMBbl)	6.4	6.3	6.6	6.9	6.1
Gas (Bcf)	71.9	71.1	74.9	66.1	56.4
BCFE	110.0	109.1	114.6	107.5	92.8

Realized price—pre hedging:					
Per Bbl	$ 72.65	$ 54.40	$ 92.99	$ 67.56	$ 59.33
Per Mcf	$ 5.21	$ 3.82	$ 8.60	$ 6.74	$ 6.58
Realized price—net of hedging:					
Per Bbl	$ 66.85	$ 56.74	$ 75.59	$ 62.60	$ 56.60
Per Mcf	$ 6.05	$ 5.59	$ 8.79	$ 7.63	$ 7.37
Expense per MCFE:					
LOE	$ 1.10	$ 1.33	$ 1.46	$ 1.31	$ 1.25
Transportation	$ 0.19	$ 0.19	$ 0.19	$ 0.14	$ 0.12
Production taxes	$ 0.48	$ 0.37	$ 0.71	$ 0.58	$ 0.54
DD&A	$ 3.06	$ 2.79	$ 2.74	$ 2.12	$ 1.67
General and administrative	$ 0.97	$ 0.70	$ 0.69	$ 0.56	$ 0.42
Statement of Cash Flow Data:					
Provided by operations	$ 497,097	$ 436,106	$ 679,190	$ 632,054	$ 467,700
Used in investing	$ (361,573)	$ (304,092)	$ (673,754)	$ (805,134)	$ (724,719)
Provided by (used in) financing	$ (141,096)	$ (127,496)	$ (42,815)	$ 215,126	$ 243,558

ITEM 7 MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This discussion includes forward-looking statements. Please refer to "Cautionary Information about Forward-Looking Statements" in Part I, Items 1 and 2 of this report for important information about these types of statements.

Overview of the Company

General Overview

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. Our assets include leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays, as well as meaningful positions in the Granite Wash, Haynesville shale, and Woodford shale resource plays. We have developed our portfolio of properties with reserves, development drilling opportunities, and unconventional resource prospects onshore in North America, typically through early entrance into existing and emerging resource plays. We believe this approach allows for stable and predictable production and reserves growth. Furthermore, by entering these plays earlier, we believe that we can reduce costs and capture larger resource potential.

We generally generate almost all our revenues and cash flows from the sale of produced natural gas, NGLs and crude oil. In 2010 we have generated significant gains and cash proceeds from the sale of non-strategic oil and gas properties. Please refer to discussion below under *2010 Highlights*.

Our business strategy is to increase net asset value through attractive oil and gas investment activity while maintaining a conservative capital structure and optimizing capital expenditures. We focus our efforts on the exploration for and development of onshore, lower-risk resource plays in North America. We believe our inventory of drilling locations is ideally suited for 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.

In 2010 we had the following financial and operational results:

- At year end 2010 we had estimated proved reserves of 984.5 BCFE, of which 65 percent were natural gas and 70 percent were characterized as proved developed. We added 384.2 BCFE from our drilling program, the majority of which related to our activity in our 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 at year end 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 regions, given the impact of lower gas prices and higher well costs on the economics of these projects. 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 SEC.

- The PV-10 value of our proved reserves was $2.3 billion as of December 31, 2010, compared with $1.3 billion as of December 31, 2009. The after tax value, represented by the standardized measure calculation, was $1.7 billion as of December 31, 2010, compared with $1.0 billion as of December 31, 2009. The standardized measure calculation is presented in Note 15 — Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report. A reconciliation between the PV-10 reserve value and the after tax value is shown under Reserves in Part I, Items 1 and 2 of this report.

- We recorded net income of $196.8 million and diluted earnings per share of $3.04 for the year ended December 31, 2010. This compares with a net loss of $99.4 million, or $1.59 loss per diluted share, for the year ended December 31, 2009.
- Our average daily production for 2010 was 196.9 MMcf of gas and 17.4 MBbl of oil, for an average equivalent production rate of 301.4 MMCFE per day, compared with 298.8 MMCFE per day for 2009.
- Cash flow from operating activities of $497.1 million, was an increase of 14 percent from 2009.
- Costs incurred for oil and gas producing activities for the year ended December 31, 2010, were $877.4 million, compared with $419.0 million for the same period in 2009.

Our operations are generally funded first through cash flows from operating activities and then through borrowings under our credit facility. The divestiture of assets is also a potential source of liquidity. Acquisitions may be funded with proceeds from sales of public or private debt and equity, borrowings under our credit facility, property sales, and cash flow from operating activities. In 2010 we invested $823.5 million for development and exploration, including facility costs, and $53.9 million for leasehold and acquisitions. Total costs incurred during 2010 increased $458.4 million, or 109 percent, to $877.4 million compared to $419.0 million in 2009. This increase in capital and exploration activities reflects a stable and improving economic environment, higher cash flows available for investment provided by operating activities and divestiture proceeds, and our increased level of drilling activity, particularly in the Eagle Ford shale.

Reserve Replacement, Finding Costs, and Growth

Like all oil and gas exploration and production companies, we face the challenge of growing oil and natural gas reserves. An exploration and production company depletes part of its asset base with each unit of oil or gas it produces. Our future growth will depend on our ability to organically and economically add reserves in excess of production.

The following table provides various reserve replacement and finding cost metrics for the year ended December 31, 2010:

	Reserve Replacement Percentage		Finding Cost per MCFE	
	Excluding sales	Including sales	Excluding sales	Including sales
Drilling, excluding revisions	349%	270%	$ 2.14	$ 2.77
Drilling, including revisions	372%	293%	$ 2.01	$ 2.56
Drilling and acquisitions, excluding revisions	349%	270%	$ 1.94	$ 2.50
Drilling and acquisitions, including revisions	372%	293%	$ 1.82	$ 2.31
Acquisitions	N/M*	N/M*	N/M*	N/M*
All-in	372%	293%	$ 2.14	$ 2.72

* N/M—Percentage is not meaningful

The following table provides three-year average reserve replacement and finding cost metrics for the years ended December 31, 2010, 2009, and 2008:

	Reserve Replacement Percentage		Finding Cost per MCFE	
	Excluding sales	Including sales	Excluding sales	Including sales
Drilling, excluding revisions	199%	141%	$ 2.83	$ 3.99
Drilling, including revisions	118%	61%	$ 4.76	$ 9.29
Drilling and acquisitions, excluding revisions	208%	150%	$ 2.65	$ 3.67
Drilling and acquisitions, including revisions	127%	69%	$ 4.33	$ 7.93
Acquisitions	9%	N/M*	$ 1.78	N/M*
All-in	127%	69%	$ 5.08	$ 9.30

* N/M—Percentage is not meaningful

Our strategic challenge is to grow net asset value per share, which we believe drives appreciation in our stock price over the long term. To accomplish this, we believe it is important to organically and economically replace annual production with new reserves. We believe annual reserve replacement percentage and finding cost amounts are important analytical measures that are widely used by investors and industry peers in evaluating and comparing the performance of oil and gas companies. While single-year measurements have some meaning in terms of a trend, we believe that aberrations, causing both relatively good and bad results, will occur over short intervals of time. The information used to calculate the above reserve replacement and finding cost 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 Part IV, Item 15 of this report. For additional

information about these metrics, see the reserve replacement and finding cost terms in the Glossary at the end of Part I, Items 1 and 2 of this report.

Financial Standing and Liquidity

In the third quarter of 2010, the borrowing base under our credit facility was redetermined and was increased from $900 million to $1.1 billion. The commitment amount of the bank group remained unchanged at $678 million. At the end of 2010, we had $48.0 million outstanding under our credit facility. Subsequent to year end, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. Pursuant to the terms of our credit facility, our borrowing base was reduced by 25 percent of the $350.0 million resulting in a new borrowing base of $1.0 billion, effective as of February 2011. The next scheduled redetermination of our borrowing base is scheduled for

April, 2011. We used a portion of the proceeds from our 6.625% Senior Notes offering to repay our outstanding balance under our credit facility. As of February 18, 2011, we had no outstanding borrowings under our credit facility. We have no debt maturities until 2012, when our credit facility matures and all or a portion of our outstanding 3.50% Senior Convertible Notes can be first put to us on April 1, 2012. If the 3.50% Senior Convertible Notes are put to us on April 1, 2012, we have the option of paying the purchase price in cash shares of our common stock, or a combination thereof. On or after April 6, 2012, we have the option of redeeming all or a portion of the outstanding 3.50% Senior Convertible Notes for cash. The 3.50% Senior Convertible Notes are convertible into shares of our common stock under certain circumstances, including if the 3.50% Senior Convertible Notes are called for redemption, and we may elect to settle conversion obligations in cash, shares of our common stock, or a combination thereof. Given the condition of our business, our debt position, credit standing, and relationships with the participants in 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.

We anticipate that cash flows from operations, proceeds from our 6.625% Senior Notes, and proceeds from additional asset divestitures will fund the majority of our 2011 capital program. We plan to use our credit facility to fund the remaining portion of our capital program. Given the magnitude of the commitments associated with our existing inventory of potential drilling projects, our funding requirements could increase significantly in 2011 and beyond. As a result, we may consider accessing the capital markets, selling assets, entering into joint ventures, and other financing alternatives as we determine the best options to fund our capital programs. We continue to believe we currently have adequate liquidity available, as discussed under the caption **Overview of Liquidity and Capital Resources**.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, natural gas, and NGL production, which can fluctuate dramatically. Please refer to *Comparison of Financial Results and Trends between 2010 and 2009* for the realized price tables for the respective periods. We sell a majority of our natural gas under contracts that use first of the month index pricing, which means that gas produced in a given month is sold at the first of the month price regardless of the spot price on the day the gas is produced. We account for the majority of our natural gas sales as they occur at the wellhead and accordingly do not present a separate production stream for the NGLs processed from our natural gas production. We receive value for the NGL content in our natural gas stream, which can result in us realizing a higher per unit price for our reported gas production. Volumes associated with the sale of processed NGLs are currently not significant and have not been included in our production volumes. We anticipate that dollars and volumes associated with our NGL production will become a growing part of our production stream and reserve base. Our crude oil is sold using contracts that pay us either the average of the NYMEX WTI daily settlement price or the average of alternative posted prices for the periods in which the crude oil is produced, adjusted for quality, transportation, and location differentials.

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The following table is a summary of commodity price data for the years ended December 31, 2010, 2009, and 2008.

	For the Years Ended December 31,		
	2010	2009	2008
Crude Oil (per Bbl):			
Average NYMEX WTI spot price	$ 79.51	$ 61.99	$ 99.92
Realized price, before the effects of hedging	$ 72.65	$ 54.40	$ 92.99
Net realized price, including the effects of hedging	$ 66.85	$ 56.74	$ 75.59
Natural Gas (per Mcf):			
Average NYMEX Henry Hub spot price	$ 4.37	$ 3.94	$ 8.89
Realized price, before the effects of hedging	$ 5.21	$ 3.82	$ 8.60
Net realized price, including the effects of hedging	$ 6.05	$ 5.59	$ 8.79

We expect future prices for crude oil, NGLs, and natural gas to be volatile. In addition to supply and demand fundamentals, the relative strength of the U.S. Dollar will likely continue to impact crude oil prices. Historically, NGL prices have trended and correlated with the price for crude oil. The supply of NGLs is expected to grow in the near term as a result of a number of industry participants targeting projects that produce these products, which could negatively impact future pricing. Natural gas prices are facing downward pressure as a result of excess supply resulting from high levels of drilling activity across the country, as well as tepid demand due to the economic recession in the United States. The 12-month strip prices for NYMEX WTI crude and NYMEX Henry Hub gas as of December 31, 2010, were $93.70 per Bbl and $4.64 per MMBTU, respectively; comparable prices as of February 18, 2011, were $94.86 per Bbl and $4.23 per MMBTU, respectively.

While changes in quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this hedge impacted price as our realized price, which excludes the effects of hedging. Our realized price is further impacted by the results of our hedging arrangements that are settled in the respective periods. We refer to this price as our net realized price. For the year ended December 31, 2010, our net natural gas price realization was positively impacted by $60.3 million of realized hedge settlements, and our net oil price realization was negatively impacted by $36.8 million of realized hedge settlements.

2010 Highlights

Operational activities. We had between ten and twelve operated drilling rigs running company-wide for most of 2010. The thrust of our operated drilling activity this year has been focused on oil and NGL-rich gas programs and selected natural gas projects of potential strategic importance to us. Our operating partners have also increased their levels of activity in oil and NGL-rich gas plays.

In our Eagle Ford shale program in South Texas, we operated a two rig drilling program on our acreage throughout 2010. Our focus was on drilling in areas with higher BTU gas content and higher condensate yields. We continued to test different ways to complete these wells with the objective of optimizing future development potential. We have been encouraged with the results in our operated portion of the play and have been working to increase the pace of development on our acreage. Securing infrastructure to gather, transport, process, and market production from our Eagle Ford shale program has been an issue we have worked to address over the last year, which has yielded benefits to us in recent months. However given increased activity across the Eagle Ford shale play as a whole, we expect that the industry, including us, will continue to experience capacity limitations as the infrastructure required to serve this play is developed and expanded. During 2010, we entered into arrangements to secure the takeaway capacity and to secure drilling and completion services required to accelerate our operated program. We continue to explore other arrangements to facilitate the growth of this program. Please refer to

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Note 6—Commitments and Contingencies under Part IV, Item 15 of this report and **Delivery Commitments** under Part I, Item 1 and 2 of this report for additional discussion concerning these agreements. On our outside-operated Eagle Ford acreage, the operator increased activity on our shared acreage throughout 2010. At year end, seven drilling rigs were running in this program. This outside-operated acreage had limited infrastructure to support the development program, and accordingly we participated in the construction projects with our partner during 2010. The increase in partner-operated rigs and the infrastructure build-out resulted in higher capital expenditures in this program than we initially budgeted for at the beginning of the year.

We operated an average of two drilling rigs in the Williston Basin throughout 2010, both of which were focused on Bakken/Three Forks drilling. Our drilling results in prospects west of the majority of industry activity met or exceeded our expectations in 2010. Elsewhere in the Rocky Mountain region, we tested the Niobrara formation in southeastern Wyoming during the year with the drilling of two test wells. Interest in the Niobrara formation increased significantly during 2010 based on positive field reports coming out of the play. Our early results from our exploratory program have been encouraging.

In our Mid-Continent region, we operated an average of two drilling rigs in our Granite Wash program in western Oklahoma. Our acreage position is held by production, and we believe the potential from this emerging program could be significant. We also operated a rig in the Woodford shale in the Arkoma Basin during the second half of 2010, which focused primarily on drilling sections of our acreage with richer natural gas.

Our Permian region operated a two-rig program throughout 2010, focusing on Wolfberry tight oil targets. In our operated Haynesville shale program, we entered into a sharing arrangement involving our East Texas acreage position in early 2010 as discussed further in Note 12 - Carry and Earning Agreement under Part IV, Item 15. The arrangement allowed us to de-risk our Haynesville shale acreage in East Texas with a considerably reduced capital investment on our part. We had two drilling rigs operating in the play for most of the second half of 2010.

Marketing of properties. In the third quarter of 2010, we began marketing two divestiture packages that included non-strategic properties in our Rocky Mountain, Mid-Continent, and Permian regions. We closed the Permian component of this package at the end of 2010. Subsequent to year end we divested the Rocky Mountain component of the package. Both divestitures are discussed in further detail below. The non-strategic properties being marketed also include all of our Marcellus shale assets in North Central Pennsylvania. We are continuing to market the Mid-Continent component of this package and our Marcellus shale assets in Pennsylvania. Finally, we have announced that we are pursuing a transaction that could result in a partial sale or farm-down of our total Eagle Ford shale position. The marketing process for our Eagle Ford shale assets began subsequent to year end. Please refer to *Outlook for 2011* and Note 3 — Divestitures and Assets Held for Sale, in Part IV, Item 15 of this report for additional information.

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 Plan payments, was $125.3 million. The final gain on divestiture activity related to the divestiture was approximately $66.7 million.

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 the divestiture was approximately $53.1 million.

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 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.

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.

Financial and production results. We recorded net income for the year ended December 31, 2010, of $196.8 million or $3.04 per diluted share compared to 2009 results of a net loss of $99.4 million or $(1.59) per diluted share.

The table below details the regional breakdown of our 2010 production:

	ArkLaTex	Mid-Continent	South Texas & Gulf Coast	Permian	Rocky Mountain	Total(1)
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

In 2010 our production growth was led by our Eagle Ford shale program. Both our operated and non-operated programs targeting the Eagle Ford contributed more production than originally budgeted. Please refer to *Comparison of Financial Results and Trends between 2010 and 2009* below for additional discussion on production.

Hedging Activities. On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The Dodd-Frank Act requires the CFTC and SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. On October 1, 2010, the CFTC introduced its first series of proposed rules coming out of the Dodd-Frank Act. The effect of the proposed rules and any additional regulations on our business is currently uncertain. Of particular concern, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. While several senators have indicated that it was not the intent of the Dodd-Frank Act to require margin from end users, the exemption is not explicit in the Dodd-Frank Act. Final rules on major provisions in the legislation, such as new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

Hedging is an important part of our financial risk management program. We have a financial risk management policy that governs our practices relating to hedging. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital commitments and long-term obligations we have in place. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the acquired production in order to protect the economics assumed in the acquisition. With the hedges we have in place, we believe we have established a base cash flow stream for our future operations, and our use of collars for a portion of the hedges allows us to participate in upward movements in oil and gas prices while also setting a price floor for a portion of our production. Please see Note 10 — Derivative Financial

Instruments of Part IV, Item 15 of this report for additional information regarding our oil and gas hedges, and see the caption, *Summary of Oil and Gas Production Hedges in Place,* later in this section.

Prior to January 1, 2011, we attempted to qualify our oil and gas derivative instruments as cash flow hedges for accounting purposes, whereby changes in the value of our hedge positions were primarily reflected in our consolidated balance sheets. A portion of the changes in the value of our hedge positions were recognized in our consolidated statements of operations when hedges were partially ineffective at offsetting the fluctuations in cash flow due to changes in the spot price for oil, natural gas, and NGLs. Effective January 1, 2011, we have elected to de-designate all of our commodity hedges that had previously been designated as cash flow hedges as of December 31, 2010. We have also elected to discontinue hedge accounting prospectively. Hedging will continue to be an important part of our financial risk management program. The election to de-designate our commodity hedges does not impact the economic substance of these transactions and changes only how these transactions are accounted for in our consolidated financial statements.

We recognized $8.9 million in non-cash unrealized derivative loss for the year ended December 31, 2010. Our overall hedge liability decreased year over year as a result of the continued deterioration in natural gas prices, which caused an increase in our natural gas hedge assets at December 31, 2010. Our net hedge liability was $52.3 million as of December 31, 2010, compared to $80.9 million at the end of 2009. Corresponding changes are reflected in accumulated other comprehensive income on the consolidated balance sheets and unrealized derivative (gain) loss on the consolidated statements of operations.

Net Profits Plan. For the year ended December 31, 2010, the change in the value of this liability resulted in a non-cash benefit of $34.4 million compared with a $7.1 million benefit for the same period in 2009. Current year payments made or accrued as part of allocating the proceeds received from divestitures in 2010 have decreased the estimated liability for the future amounts to be paid to plan participants. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

Payments made or accrued under the Net Profits Plan have been expensed as compensation costs in the amounts of $22.4 million, $19.9 million, and $36.3 million for the years ended December 31, 2010, 2009, and 2008, respectively. Additionally, the divestiture of oil and gas properties described above included a number of properties included in the net profits pools and resulted in payments made or accrued under the Net Profits Plan of $26.1 million for the year ended December 31, 2010. For the years ended December 31, 2009, and 2008, we made or accrued cash payments under the Net Profits Plan of $724,000 and $15.1 million, respectively, as a result of divestitures. These cash payments are accounted for as a reduction in the gain on divestiture activity in the accompanying consolidated statements of operations.

The recurring cash payments we make are dependent on actual production, realized prices, and operating and capital costs associated with the properties in each individual pool. Actual cash payments will be inherently different from the estimated liability amounts. More detailed discussion is included in the analysis in the *Comparison of Financial Results and Trends* section below and in Note 11 — Fair Value Measurements in Part IV, Item 15. An increasing percentage of the costs associated with the payments from the Net Profits Plan are being categorized as general and administrative expense as compared to exploration expense. This is a function of the normal departure of employees who previously contributed to our exploration efforts. In December 2007, our Board of Directors approved an incentive compensation plan restructuring, whereby the Net Profits Plan was replaced with a long-term incentive program utilizing equity awards. As a result, the 2007 Net Profits Plan pool was the last pool established.

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions. For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at December 31, 2010, would differ by approximately $12 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $7 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $6 million. We frequently re-evaluate the assumptions used in our calculations and

consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions for oil and gas properties.

Outlook for 2011

We enter the year with a capital expenditure budget of approximately $1.0 billion, of which approximately $830.0 million will be spent drilling activity. Approximately 80 percent of our drilling capital budget will be deployed in our Eagle Ford shale and Bakken/Three Forks programs during the year.

We began 2011 operating two rigs on our Eagle Ford acreage with plans to increase our operated rig count to five or six drilling rigs by year end. We have extended the contracts for two rigs currently working for us and have also contracted for two additional rigs, which are scheduled to be available in mid-2011. We have also been working with completion service providers to ensure we have access to certain services throughout the year. We have made commitments that secure a portion of our required services and we continue to work with providers to support our anticipated level of activity. During 2010 we entered into separate arrangements that increase our gas takeaway capacity in 2011 and beyond in this play. Our current export capacity is approximately 100 MMcf per day, which we anticipate will increase to 150 MMcf per day around mid-2011. During the same time frame, capacity under a separate agreement is scheduled to be available which will ultimately provide an additional 160 MMcf per day in the next several years.

In our non-operated Eagle Ford shale program, the operator is currently operating seven drilling rigs and our expectation is that such number will increase to ten rigs by the end of the first quarter of 2011. The operator has indicated that it is exploring various transactions which could allow it to increase activity even further. We have initiated a marketing effort to sell down or joint venture a portion of our Eagle Ford shale position. Although details of the contemplated transaction are still being determined, we estimate that we could farm down or joint venture approximately 20 to 30 percent of our total acreage position, resulting in a net investment by us in the Eagle Ford in 2011 of approximately $500 million.

We plan to deploy approximately $170 million of our capital budget in our Bakken/Three Forks formations in the Williston Basin in 2011. We currently are operating two drilling rigs in this program and plan to add a third rig by mid-year. We would consider increasing activity in this program beyond three rigs should additional capital become available for investment during the year and other circumstances warrant such action.

We also have activity planned in our Granite Wash, Permian Basin, and Haynesville shale programs in 2011. Approximately $60 million of our capital budget in

2011 is budgeted for our Granite Wash program, where we anticipate operating a two rig program throughout the year. We plan to spend approximately $40 million of our capital budget in our Permian region in 2011, where approximately 50 percent of our activity will be focused on our vertical Wolfberry tight oil program. In the Haynesville shale, our capital budget is approximately $35 million, related primarily to non-operated activity. Five operated wells in our Haynesville shale program are currently anticipated for the year, of which the majority of our costs will be carried under the previously announced carry and earning agreement covering a portion of our operated Haynesville shale acreage in East Texas. We are currently exploring a number of 2011 and 2012 drilling options for our operated Haynesville shale acreage position in East Texas that would allow us to drill enough wells in 2011 and 2012 to hold substantially all of our existing acreage, while minimizing the amount of capital deployed by us. Please refer to additional discussion under Note 12 — Carry and Earning Agreement under Part IV, Item 15 of this report.

Please refer to *Overview of Liquidity and Capital Resources* for additional discussion regarding how we anticipate funding our 2011 capital program.

Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended December 31, 2010, and the immediately preceding three quarters. Additional details of per MCFE costs are contained later in this section.

	For the Three Months Ended			
	December 31, 2010	September 30, 2010	June 30, 2010	March 31, 2010
	(in millions, except production sales data)			
Production (BCFE)	31.6	27.5	25.2	25.7
Oil and gas production revenue, excluding the effects of hedging	$ 250.1	$ 197.4	$ 175.9	$ 212.9
Realized oil and gas hedge gain	$ 2.8	$ 8.8	$ 9.3	$ 2.6
Gain on divestiture activity	$ 23.1	$ 4.2	$ 7.0	$ 121.0
Lease operating expense	$ 33.5	$ 29.0	$ 29.0	$ 30.0
Transportation costs	$ 7.1	$ 4.9	$ 5.1	$ 4.1
Production taxes	$ 16.4	$ 10.7	$ 11.1	$ 14.2
DD&A	$ 94.7	$ 83.8	$ 79.8	$ 77.8
Exploration	$ 21.1	$ 14.4	$ 14.5	$ 13.9
General and administrative	$ 31.6	$ 26.2	$ 25.4	$ 23.5
Change in Net Profits Plan liability	$ (4.6)	$ 4.1	$ (6.6)	$ (27.3)
Unrealized derivative (gain) loss	$ 13.0	$ 5.7	$ (2.1)	$ (7.7)
Net income	$ 37.0	$ 15.5	$ 18.1	$ 126.2
Percentage change from previous quarter:				
Production (BCFE)	15%	9%	(2)%	(2)%
Oil and gas production revenue, excluding the effects of hedging	27%	12%	(17)%	13%
Realized oil and gas hedge gain	(68)%	(5)%	258%	(81)%
Gain on divestiture activity	450%	(40)%	(94)%	448%
Lease operating expense	16%	—%	(3)%	(13)%
Transportation costs	45%	(4)%	24%	(21)%
Production taxes	53%	(4)%	(22)%	7%
DD&A	13%	5%	3%	4%
Exploration	47%	(1)%	4%	4%
General and administrative	21%	3%	8%	14%
Change in Net Profits Plan liability	(212)%	(162)%	(76)%	(490)%
Unrealized derivative (gain) loss	128%	(371)%	(73)%	(341)%
Net income	139%	(14)%	(86)%	12,520%

A year to year overview of selected reserve, production and financial information, including trends:

Selected Operations Data (in thousands, except sales price, volumes, and per MCFE amounts):

	As of and for the Years Ended December 31,			Percent Change Between	
	2010	2009	2008	2010/2009	2009/2008
Total proved reserves					
Oil (MMBbl)	57.4	53.8	51.4	7%	5%
Natural gas (Bcf)	640.0	449.5	557.4	42%	(19)%
BCFE	984.5	772.2	865.5	27%	(11)%
Net production volumes					
Oil (MMBbl)	6.4	6.3	6.6	—%	(4)%
Natural gas (Bcf)	71.9	71.1	74.9	1%	(5)%
BCFE	110.0	109.1	114.6	1%	(5)%
Average daily production					
Oil (MBbl)	17.4	17.3	18.1	—%	(4)%

Natural gas (MMcf)	196.9	194.8	204.7	1%	(5)%
MMCFE	301.4	298.8	313.1	1%	(5)%
Oil & gas production revenues					
Oil production, including hedging	$ 425,104	$ 359,075	$ 500,062	18%	(28)%
Gas production, including hedging	434,649	397,526	658,242	9%	(40)%
Total	$ 859,753	$ 756,601	$ 1,158,304	14%	(35)%
Oil & gas production costs					
Lease operating expenses	$ 121,544	$ 145,463	$ 167,384	(16)%	(13)%
Transportation costs	21,175	20,657	22,205	3%	(7)%
Production taxes	52,356	40,680	81,766	29%	(50)%
Total	$ 195,075	$ 206,800	$ 271,355	(6)%	(24)%
Average net realized sales price(1)					
Oil (per Bbl)	$ 66.85	$ 56.74	$ 75.59	18%	(25)%
Natural gas (per Mcf)	$ 6.05	$ 5.59	$ 8.79	8%	(36)%
Per MCFE data					
Average net realized price(1)	$ 7.82	$ 6.94	$ 10.11	13%	(31)%
Lease operating expense	(1.10)	(1.33)	(1.46)	(17)%	(9)%
Transportation costs	(0.19)	(0.19)	(0.19)	—%	—%
Production taxes	(0.48)	(0.37)	(0.71)	30%	(48)%
General and administrative	(0.97)	(0.70)	(0.69)	39%	1%
Operating profit	$ 5.08	$ 4.35	$ 7.06	17%	(38)%
Depletion, depreciation and amortization	$ 3.06	$ 2.79	$ 2.74	10%	2%

(1) Includes the effects of our hedging activities.

We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe require analysis. Average daily production for the year ended December 31, 2010, increased one percent to 301.4 MMCFE compared with 298.8 MMCFE for the same period in 2009, driven mainly by the development of our Eagle Ford program. Adjusting for divestitures, our average daily production from retained properties for the year ended December 31, 2010, increased 12 percent to 294.0 MMCFE compared with 262.3 MMCFE for the same period in 2009.

Changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our average net realized price for the year ended December 31, 2010, was $7.82 per MCFE compared with $6.94 per MCFE for the same period in 2009. The increase in our equivalent realized price for production corresponds with stronger commodity prices in 2010 when compared with 2009.

Our LOE for the year ended December 31, 2010, decreased 17 percent to $1.10 per MCFE compared with $1.33 for the same period in 2009. The divestiture of non-strategic properties with meaningfully higher operating costs is the primary reason for the decline in LOE from 2009. We believe the steady increase in industry activity we have experienced will put upward pressure on lease operating costs in 2011. Production taxes for year ended December 31, 2010, increased 30 percent to $0.48 per MCFE compared with $0.37 for the same period in 2009.

Production taxes are highly correlated to pre-hedge oil and gas revenues, and stronger commodity prices have impacted results for this expense item. Transportation costs remained steady at $0.19 per MCFE for the years ended December 31, 2010, and 2009. Our general and administrative expense for the year ended December 31, 2010, increased 39 percent to $0.97 per MCFE compared to $0.70 per MCFE for the same period in 2009. A portion of our general and administrative expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. The Net Profits Plan and a portion of our current short-term incentive compensation are tied to net revenues and therefore are subject to variability. Our operating profit for the year ended December 31, 2010, increased 17 percent to $5.08 per MCFE compared to $4.35 per MCFE for the same period in 2009.

Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the year ended December 31, 2010, increased ten percent to $3.06 per MCFE compared to $2.79 per MCFE for the same period in 2009. Depreciation, depletion, and amortization was impacted by our divestiture of lower cost basis properties in the first quarter of 2010. Additionally, we have been impacted by higher DD&A rates in our Eagle Ford and Haynesville shales. We are incurring capital for research wells and infrastructure that will benefit future development in these plays but are currently limited in the amount of reserves we can record to carry the costs, which results in higher per unit DD&A costs early in the lives of these plays. Our DD&A rate can also fluctuate as a result of impairments, divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Additionally, the accounting treatment for assets that are classified as assets held for sale can impact our DD&A rate since properties held for sale are not depleted.

Please refer to *Comparison of Financial Results and Trends between 2010 and 2009* for additional discussion on oil and gas production expense, DD&A, and general and administrative expense.

Financial information (in thousands, except per share amounts):

	As of and for the Years Ended December 31,			Percent Change Between	
	2010	**2009**	**2008**	**2010/2009**	**2009/2008**
Working capital (deficit)	$ (227,408)	$ (87,625)	$ 15,193	160%	(677)%
Long-term debt	$ 323,673	$ 454,902	$ 558,713	(29)%	(19)%
Stockholders' equity	$ 1,218,526	$ 973,570	$ 1,162,509	25%	(16)%
Net income	$ 196,837	$ (99,370)	$ 87,348	(298)%	(214)%
Basic net income per common share	$ 3.13	$ (1.59)	$ 1.40	(297)%	(214)%
Diluted net income per common share	$ 3.04	$ (1.59)	$ 1.38	(291)%	(215)%
Basic weighted-average shares outstanding	62,969	62,457	62,243	1%	—%
Diluted weighted-average shares outstanding	64,689	62,457	63,133	4%	(1)%

Net cash provided by operating activities	$	497,097	$	436,106	$	679,190	14%	(36)%
Net cash used in investing activities	$	(361,573)	$	(304,092)	$	(673,754)	19%	(55)%
Net cash used in financing activities	$	(141,096)	$	(127,496)	$	(42,815)	11%	198%

We present this table as a summary of information relating to key indicators of financial condition and operating performance that we believe are important.

We account for our 3.50% Senior Convertible Notes under the treasury stock method. There is no impact on the diluted share calculation for the periods presented since our average stock price for the relevant reporting periods has not exceeded the conversion price. The 3.50% Senior Convertible Notes were issued April 4, 2007, and have not been dilutive for a reporting period since their issuance. Subsequent to December 31, 2010, our stock has consistently been trading above the $54.42 conversion price and as such we expect the 3.50% Senior Convertible Notes to have a dilutive impact on our first quarter 2011 dilutive earnings per share calculation. We have in-the-money stock options, unvested RSUs, and contingent

PSAs that may be potentially dilutive securities. There were no potentially dilutive shares related to in-the-money stock options, unvested RSUs, and contingent PSAs included in the diluted earnings per share calculation for the year ended December 31, 2009, as we recorded a net loss for the period. Both basic and diluted earnings per share are presented in the table above. A detailed explanation is presented under the caption *Earnings per Share* included in Note 1 — Summary of Significant Accounting Policies, in Part IV, Item 15 of this report.

Basic and diluted weighted-average common shares outstanding used in our 2010, 2009, and 2008 earnings per share calculations reflect our stock repurchases, offset by increases in outstanding shares related to stock option exercises, ESPP shares issued, and vested RSUs. We issued 346,377, 189,740, and 868,372 shares of common stock in 2010, 2009, and 2008, respectively, as a result of stock option exercises. The number of RSUs that vested in 2010, 2009, and 2008 were 160,398, 211,092, and 291,659, respectively. The number of ESPP shares issued totaled 52,948, 86,308, and 45,228 in 2010, 2009, and 2008, respectively. These share issuances were offset by the repurchase of 2,135,600 shares of common stock in 2008 through our stock repurchase plan. There were no shares of common stock repurchased in the open market in 2010 or 2009.

Additional Comparative Data in Tabular Format:

	Change Between Years			
	2010 and 2009		2009 and 2008	
Oil and Gas Production Revenues:				
Increase (decrease) in oil and gas production revenues, net of hedging (in thousands)	$	103,152	$	(401,703)
Components of Revenue Increases (Decreases):				
Oil				
Realized price change per Bbl, net of hedging	$	10.11	$	(18.85)
Realized price percent change		18%		(25)%
Production change (MMBbl)		0.1		(0.3)
Production percentage change		—%		(4)%
Natural Gas				
Realized price change per Mcf, net of hedging	$	0.46	$	(3.20)
Realized price percentage change		8%		(36)%
Production change (Bcf)		0.8		(3.8)
Production percentage change		1%		(5)%

Our product mix as a percentage of total oil and gas revenue, including the effects of hedging, and production:

	Years Ended December 31,		
	2010	2009	2008
Revenue			
Oil	49%	47%	43%
Natural Gas	51%	53%	57%
Production			
Oil	35%	35%	35%
Natural Gas	65%	65%	65%

Information regarding the effects of oil and gas hedging activity:

	Years Ended December 31,					
		2010		2009		2008
Oil Hedging						
Percentage of oil production hedged		47%		52%		61%
Oil volumes hedged (MBbl)		2,999		3,306		4,022
Increase (Decrease) in oil revenue	$	(36.8) million	$	14.8 million	$	(115.1) million
Average realized oil price per Bbl before hedging	$	72.65	$	54.40	$	92.99
Average realized oil price per Bbl after hedging	$	66.85	$	56.74	$	75.59
Natural Gas Hedging, including NGLs						
Percentage of gas production hedged		43%		45%		46%
Natural gas volumes hedged (MMBtu)		34.6 million		34.3 million		36.4 million

Increase in gas revenue	$	60.3 million	$	125.9 million	$	14.0 million
Average realized gas price per Mcf before hedging	$	5.21	$	3.82	$	8.60
Average realized price per Mcf after hedging	$	6.05	$	5.59	$	8.79

Information regarding the components of exploration expense:

	Years Ended December 31,					
Summary of Exploration Expense (in millions)	**2010**		**2009**		**2008**	
Geological and geophysical expenses	$	21.5	$	20.2	$	14.2
Exploratory dry holes		0.3		7.8		6.8
Overhead and other expenses		42.1		34.2		39.1
Total	$	63.9	$	62.2	$	60.1

Comparison of Financial Results and Trends between 2010 and 2009

Oil and gas production revenue. Average daily production for the year ended December 31, 2010, increased one percent to 301.4 MMCFE compared with 298.8 MMCFE for the same period in 2009. The following table presents the regional changes in our production and oil and gas revenues and costs between the two years.

	Average Net Daily Production Added/(Lost) (MMCFE)	Pre-Hedge Oil and Gas Revenue Added (in millions)		Production Costs Increase/ (Decrease) (in millions)	
ArkLaTex	(1.5)	$	7.4	$	(5.8)
Mid-Continent	(7.2)		23.9		4.0
South Texas & Gulf Coast	35.4		131.4		20.6
Permian	(1.3)		37.8		2.2
Rocky Mountain	(22.8)		19.8		(32.7)
Total	2.6	$	220.3	$	(11.7)

The largest regional production decrease occurred in the Rocky Mountain region as a result of our divestitures of non-strategic oil and gas assets that occurred in the fourth quarter of 2009 and first quarter of 2010. The largest production growth occurred in our South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program. We expect to grow our overall full year production in 2011.

The following table summarizes the average realized prices we received in 2010 and 2009, before the effects of hedging:

	For the Years Ended December 31, 2010		2009	
Realized oil price ($/Bbl)	$	72.65	$	54.40
Realized gas price ($/Mcf)	$	5.21	$	3.82
Realized equivalent price ($/MCFE)	$	7.60	$	5.65

The 35 percent increase in average realized prices per MCFE coupled with a one percent increase in production volumes between periods resulted in higher oil and gas revenue. We expect our realized price to trend with commodity prices.

Realized oil and gas hedge gain. We recorded a net realized hedge gain of $23.5 million for the year ended December 31, 2010, compared with a net realized hedge gain of $140.6 million for the same period in 2009. These gains were mainly related to favorable settlements on natural gas hedges. Please refer to our discussion above under the heading *Oil, Gas, and NGL Prices*.

Marketed gas system revenue and expense. Marketed gas system revenue increased $11.6 million to $70.1 million for the year ended December 31, 2010, compared with $58.5 million for the year ended December 31, 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $9.1 million to $66.7 million for the year ended December 31, 2010, compared with $57.6 million for the comparable period of 2009. We expect that marketed gas system revenue and expense will continue to trend with increases and decreases in production and our net realized price for natural gas.

Gain on divestiture activity. We recorded a gain on divestiture activity of $155.3 million for the year ended December 31, 2010, compared with $11.4 million for the comparable period of 2009. The 2010 gain relates to the divestitures of non-strategic oil and gas properties located in our Rocky Mountain and Permian regions as discussed above. The 2009 gain was mainly related to the Hanging Woman Basin property divestiture that closed in late 2009. The final gain on divestiture activity related to the Permian divestiture will be adjusted for normal post-closing adjustments and is expected to be finalized in the first half of 2011. We are currently marketing other oil and gas properties, and we will continue to evaluate property for divestiture in the normal course of our business. Please refer to *Marketing of properties* under *2010 Highlights* for additional discussion.

Oil and gas production expense. Total production costs decreased $11.7 million or six percent to $195.1 million for the year ended December 31, 2010, compared with $206.8 million in 2009. Total oil and gas production costs per MCFE decreased $0.12 to $1.77 for the year ended December 31, 2010, compared with $1.89 in 2009. This decrease is comprised of the following:

- A $0.23 decrease in recurring LOE on a per MCFE basis reflects the sale of non-strategic properties in late 2009 and early 2010 with higher per unit LOE costs that resulted in lower LOE on a per unit basis year over year. We expect the various resources required to service our industry will become more sought after and harder to secure as a result of an increase in activity. We expect to see upward pressure on LOE in 2011.

- An $0.11 increase in production taxes on a per MCFE basis is due to the increase in realized prices between periods. We expect production taxes to trend with commodity prices over time.

- Workover LOE on a per MCFE basis remained flat year over year.

- Transportation costs on a per MCFE basis remained flat year over year. We anticipate transportation costs will increase over the next year on a per MCFE basis given the increase in production expected from programs with higher transportation costs.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $31.9 million, or ten percent, to $336.1 million in 2010 compared with $304.2 million in 2009. DD&A expense per MCFE increased ten percent to $3.06 in 2010 compared to $2.79 in 2009. Please refer to discussion under the heading *Selected Operations Data* under Overview of the Company. Any future proved property impairments, divestitures, and changes in underlying proved reserve volumes will impact our DD&A expense.

Exploration. Exploration expense increased $1.7 million or three percent to $63.9 million in 2010 compared with $62.2 million for the same period in 2009. The overall increase in expense primarily relates to an increase in exploration overhead, which is partially offset by a decrease in exploratory dry hole expense. In 2009, we had $7.8 million of exploratory dry hole expense related to properties in our ArkLaTex region compared with minimal exploratory dry hole expense in the current year. Other increases in exploration costs related to an increase in equity incentive compensation expense are discussed under *General and administrative* below.

Impairment of proved properties. We recorded a $6.1 million impairment of proved oil and gas properties in 2010 compared to $174.8 million in 2009. A significant decrease in commodity prices, including differentials, during the first quarter of 2009 caused the majority of the non-cash impairment. The largest portion of the impairment in 2009 was $97.3 million related to assets located in the Mid-Continent region which were impacted at the end of the first quarter by low natural gas prices and wider than normal differentials. We generally expect proved property impairments will be more likely to occur in periods of low commodity prices.

Abandonment and impairment of unproved properties. During 2010, we abandoned or impaired $2.0 million of unproved properties compared with $45.4 million for 2009. The largest specific components of the 2009 impairment and abandonment related to our Floyd shale acreage located in Mississippi and certain acreage in Oklahoma. Additionally in 2009, we incurred write-offs related to acreage that we did not maintain based on our current capital allocation plans or related to acreage that we do not believe will be prospective. We generally expect impairments of unproved properties to be more likely to occur in periods of low commodity prices since fewer dollars will be available for exploratory and development efforts.

Impairment of materials inventory. There were no impairments of materials inventory recorded in 2010. We recorded a $14.2 million impairment of materials inventory for the year ended December 31, 2009. The 2009 inventory impairment was caused by a decrease in the value of tubular goods and other raw materials. Impairments of materials inventory are impacted by fluctuations in the materials cost environment and increases and decreases in development and exploration activity, which generally trend with commodity prices.

General and administrative. General and administrative expense increased $30.7 million or 40 percent, to $106.7 million for the year ended December 31, 2010, compared with $76.0 million for the same period in 2009. G&A increased $0.27 to $0.97 per MCFE for the year ended December 31, 2010, compared to $0.70 per MCFE for the same period in 2009.

General and administrative expense increased due to a $21.9 million increase in base compensation, cash bonus, and long-term incentive compensation expense for the year ended December 31, 2010, compared with the same period in 2009. The increase in cash bonus and long-term incentive compensation expense reflects compensation expense associated with the PSAs granted in the third quarter of 2010, as well as the improvement in our performance and the anticipated achievement of various performance criteria, established by our Compensation Committee.

Additionally, G&A expense increased as a result of a $5.1 million decrease in COPAS overhead reimbursements, caused by a decrease in our operated well count resulting from our recent divestiture efforts, and a $1.4 million increase in cash payments accrued under the Net Profits Plan. We expect payments made under the Net Profits Plan to trend with commodity prices.

Bad debt expense (recovery). We did not record any bad debt expense or recovery of bad debt expense in 2010. In 2008 SemGroup, L.P. and certain of its North American subsidiaries filed for bankruptcy protection. At that time, certain SemGroup L.P. entities purchased a portion of our crude oil production. As a result of the bankruptcy filing, we recorded bad debt expense of $16.6 million as of December 31, 2008. In 2009, we sold a

portion of our SemGroup L.P. administrative claim at which time we recorded a recovery of bad debt expense of $5.2 million.

Change in Net Profits Plan liability. For 2010 this non-cash item was a $34.4 million benefit compared to a $7.1 million benefit for 2009. We broadly expect the change in this liability to trend with commodity prices but it can be impacted by divestiture activity. Please refer to discussion under the heading *Net Profits Plan* under Overview of the Company.

Unrealized derivative loss. We recognized a loss of $8.9 million in 2010 compared to a loss of $20.5 million for 2009. This non-cash item is driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes. Please refer to discussion under the heading *Hedging Activities* under Overview of the Company.

Other expense. Other expense decreased $10.5 million to $3.0 million in 2010 compared with $13.5 million in 2009. During 2009 we incurred $1.5 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region and incurred a loss related to hurricanes of $8.3 million.

Income tax benefit (expense). Income tax expense totaled $118.1 million for 2010 compared to a tax benefit of $60.1 million for 2009, resulting in effective tax rates of 37.5 percent and 37.7 percent, respectively. The effective rate change from 2009 primarily reflects changes in the mix of the highest marginal state tax rates, anticipated utilization of state tax net operating losses, and differing effects of other permanent differences including percentage depletion. Our current income tax expense in 2010 is $3.5 million compared to current income tax benefit of $20.4 million in 2009. These amounts are three percent and 34 percent, respectively, of the total income tax expense or benefit for each period.

Qualified property placed in service in 2009 was eligible for 50 percent bonus depreciation as a result of tax law passed in 2008. At the end of 2010, to aid a perceived slowly recovering economy, Federal legislation was passed making qualified property placed in service after September 8, 2010, and before January 1, 2012, eligible for 100 percent bonus depreciation. This same law makes qualified property placed in service between January 1, 2010, and December 31, 2012, eligible for the 50 percent bonus depreciation election. Since we are currently in an accelerated development mode on several of our unconventional projects we will not receive much of a current benefit resulting solely from this deduction. However, making this election for 2010 accelerates deductions impacting our alternative minimum tax calculations in future years providing us with an anticipated opportunity, given current development expectations, to limit the impact of alternative minimum tax on the calculation of current income tax expense in those years. The amounts of current income tax expense reported above reflect our election to utilize bonus depreciation for both years. The benefit of bonus depreciation in 2010 was limited by alternative minimum tax calculations related to intangible drilling costs. Our 2009 current income tax benefit reflects creation of a net operating loss due in part to bonus depreciation which we carried back to 2005 to obtain a refund.

At December 31, 2010, we have utilized net operating losses to offset all prior year income for open tax years. The ability to record benefit from future net operating loss deductions will depend upon our ability to justify utilization of those losses in future tax years. The Administration's Fiscal Year 2011 Budget includes proposals for legislation that would, if enacted into law, make significant changes to U.S. tax laws, which could eliminate or postpone certain U.S. federal income tax incentives currently available to oil and gas exploration and production companies. Proposed changes include, but are not limited to (i) repeal of the percentage depletion allowance for oil and gas properties, (ii) elimination of current deductions for intangible drilling and development costs, (iii) elimination of the deduction for certain domestic production activities, and (iv) extension of the amortization period for certain geological and geophysical expenditures. Each of these changes is proposed to be effective for taxable years beginning, or in the case of costs described in (ii) and (iv), costs paid or incurred, after December 31, 2010. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. Enactment of these changes would be expected to negatively impact our effective tax rate and the cash tax portion of our income tax expense would increase in the year the legislation became effective.

Comparison of Financial Results between 2009 and 2008

Oil and gas production revenue. Production decreased five percent to 109.1 BCFE for the year ended December 31, 2009, compared with 114.6 BCFE for the year ended December 31, 2008. Production for the year ended December 31, 2009, included approximately 5.1 BCFE related to non-strategic properties divested throughout 2009. Adjusting for divestitures of non-strategic properties that were sold in the last two years, production on retained properties declined slightly from 104.5 BCFE in 2008 to 104.0 BCFE in 2009. The following table presents the regional changes in our production and oil and gas revenues and costs between the two years:

	Average Net Daily Production Added/(Lost) (MMCFE)	Pre-Hedge Oil and Gas Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
ArkLaTex	(9.9)	$ (115.0)	$ (1.1)
Mid-Continent	8.5	(142.1)	(16.4)
South Texas & Gulf Coast	(12.4)	(97.0)	(13.8)
Permian	3.7	(79.1)	(1.7)
Rocky Mountain	(4.2)	(210.2)	(31.6)
Total	(14.3)	$ (643.4)	$ (64.6)

Daily production decreased by approximately 14.3 MMCFE during 2009 compared to 2008. Production decreased between these two periods as a result of decreased levels of capital investment throughout 2009 and the lack of contribution in 2009 from properties that were sold in the second half of 2008. The largest regional increase between 2009 and 2008 occurred in the Mid-Continent region as a result of success in the horizontal Woodford shale program in the Arkoma Basin and strong results from our Deep Springer program in the Anadarko Basin. Production growth in the Permian region was the result of continued development of Wolfberry assets at Sweetie Peck and Halff East. The decrease in the South Texas & Gulf Coast region's production was primarily a result of the loss of production from the Judge Digby Field due to an exchange of assets that occurred in late 2008. The decrease in our ArkLaTex region was due to natural decline and decreased levels of capital investment in the region by us and our partners, particularly at the Elm Grove Field. The Rocky Mountain region realized a slight decline as a result of its more mature production decline profile and modest capital investment.

The following table summarizes the average realized prices we received in 2009 and 2008, before the effects of hedging:

	For the Years Ended December 31, 2009	2008
Realized oil price ($/Bbl)	$ 54.40	$ 92.99
Realized gas price ($/Mcf)	$ 3.82	$ 8.60
Realized equivalent price ($/MCFE)	$ 5.65	$ 10.99

The 49 percent decrease in average realized prices per MCFE coupled with a five percent decrease in production volumes between periods resulted in lower oil and gas revenue.

Realized oil and gas hedge gain (loss). We recorded a net realized hedge gain of $140.6 million for the year ended December 31, 2009, mainly related to favorable settlements on gas hedges. For the year ended December 31, 2008, we recorded a net realized hedge loss of $101.1 million mainly due to unfavorable settlements on oil hedges.

Marketed gas system revenue and expense. Marketed gas system revenue decreased $18.9 million to $58.5 million for the year ended December 31, 2009, compared with $77.4 million for the comparable period of 2008. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased $14.6 million to $57.6 million for the year ended December 31, 2009, compared with $72.2 million for the comparable period of 2008.

Gain on divestiture activity. We recorded a gain on divestiture activity of $11.4 million for the year ended December 31, 2009, compared with $63.6 million for the comparable period of 2008. The 2009 gain was mainly related to the Hanging Woman Basin divestiture that closed in December of 2009, which was subject to normal post-closing adjustments and was finalized during 2010. The 2008 gain was mainly related to the Abraxas divestiture that closed in January 2008.

Oil and gas production expense. Total production costs decreased $64.6 million or 24 percent to $206.8 million for the year ended December 31, 2009, compared with $271.4 million in 2008. Total oil and gas production costs per MCFE decreased $0.47 to $1.89 for the year ended December 31, 2009, compared with $2.36 in 2008. This decrease was comprised of the following:

- A $0.34 decrease in production taxes on a per MCFE basis due to the decrease in realized prices between periods.
- A $0.11 decrease in recurring lease operating expense on a per MCFE basis was related to reductions in recurring LOE that stemmed from the slowdown in

activity in the exploration and production industry, as well as the broader economy.

- A $0.02 decrease in overall workover LOE on a per MCFE basis was related to a reduction in the amount of workovers that were performed given the slowdown in activity in the exploration and production industry.

- Transportation costs on a per MCFE basis remained flat year over year.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A decreased $10.1 million, or three percent, to $304.2 million in 2009 compared with $314.3 million in 2008. DD&A expense per MCFE increased two percent to $2.79 in 2009 compared to $2.74 in 2008. The decrease in absolute DD&A reflected lower total production volumes in 2009 compared to 2008. The DD&A expense per MCFE increase reflects the industry trend of increased amounts of investment to add reserves. Generally, as these recently acquired or developed assets become a larger portion of our asset base, our DD&A expense will increase as those acquisitions and developments were made at higher costs.

Exploration. Exploration expense increased $2.1 million or four percent to $62.2 million in 2009 compared with $60.1 million for 2008. The increase was due to a $1.0 million increase in exploratory dry hole expense and a $6.0 million increase in geological and geophysical expense due to an increase in the amount spent on seismic. These increases were offset by a $4.9 million decrease in exploration overhead expense due to a decrease in Net Profits Plan payments as a result of decreased oil and gas commodity prices.

Impairment of proved properties. We recorded a $174.8 million impairment of proved oil and gas properties in 2009 compared to $302.2 million in 2008. A significant decrease in commodity prices, including differentials, during the first quarter of 2009 caused the majority of the non-cash impairment. The largest portion of the impairment in 2009 was $97.3 million related to assets located in the Mid-Continent region which were impacted at the end of the first quarter by low natural gas prices and wider than normal differentials. Our ArkLaTex region was impacted by a $20.4 million impairment related to negative pricing and engineering revisions. We incurred a $14.0 million impairment on proved properties related to the write-down of certain assets located in the Gulf of Mexico in which we are relinquishing our ownership interests.

Abandonment and impairment of unproved properties. During 2009, we abandoned or impaired $45.4 million of unproved properties compared with $39.0 million for 2008. The largest specific components of the 2009 impairment and abandonment related to our Floyd shale acreage located in Mississippi and certain

acreage in Oklahoma. Additionally, we incurred write-offs related to acreage we believe we would not keep based on our capital allocation plans or related to acreage that we did not believe to be prospective.

Impairment of Goodwill. We recorded a $9.5 million impairment of goodwill in 2008. The goodwill was the result of our purchase of Agate Petroleum, Inc. in January 2005. The impairment was a result of downward price adjustments to reserves for properties located in our Mid-Continent and Rocky Mountain regions and represented our entire goodwill balance. We had no goodwill impairment in 2009.

Impairment of materials inventory. We recorded a $14.2 million impairment of materials inventory for the year ended December 31, 2009. There were no impairments recorded in 2008. The inventory impairment was caused by a decrease in the value of tubular goods and other raw materials.

General and administrative. General and administrative expense decreased $3.5 million or four percent to $76.0 million for the year ended December 31, 2009, compared with $79.5 million for the same period in 2008. G&A increased $0.01 to $0.70 per MCFE for the year ended December 31, 2009, compared to $0.69 per MCFE for the same period in 2008.

General and administrative expense decreased due to an $11.3 million decrease in cash payments made under the Net Profits Plan. As a result of the lower price realization we received in 2009 compared to 2008, the payouts from this plan were meaningfully smaller than those paid out in the prior year.

Compensation related costs allocated to general and administrative expense increased in 2009. The largest increases were for headcount related costs, such as salary, benefits, and payroll taxes, which increased $10.6 million for the year ended December 31, 2009, when compared with the same period in 2008. A significant driver of this headcount increase was the conversion from contract lease operators to internal lease operators which began to take place in 2008. Stock compensation was also up $ 3.3 million year over year as a result of layering in the second year of stock compensation amortization from our PSA long-term incentive program. COPAS overhead reimbursements were $6.4 million higher for the year ended December 31, 2009, compared with the same period in 2008.

Bad debt expense (recovery). We recorded a recovery of bad debt expense of $5.2 million in 2009. We recorded $16.7 million of bad debt expense in 2008 of which $16.6 million was a result of SemGroup L.P. and certain of its North American subsidiaries filing for bankruptcy protection. Certain SemGroup entities had purchased a portion of our crude oil production. This amount related to oil produced in June and July of 2008 that was fully reserved in the year ended December 31, 2008.

Change in Net Profits Plan liability. For the year ended December 31, 2009, this non-cash item was a $7.1 million benefit compared to a $34.0 million benefit for the same period in 2008. Significant decreases in oil and gas commodity prices decreased the estimated liability for the future amounts to be paid to plan participants.

Unrealized derivative (gain) loss. We recognized a loss of $20.5 million for the year ended December 31, 2009, compared to a gain of $11.2 million for the same period in 2008. This non-cash item was driven by the change in the value of our hedge position, as well as the portion of that position that is considered ineffective for accounting purposes.

Other expense. Other expense increased $3.1 million to $13.5 million for the year ended December 31, 2009, compared with $10.4 million for the same period in 2008. During the year ended December 31, 2009, we incurred $1.5 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region. We also incurred a loss related to hurricanes of $8.3 million for the year ended December 31, 2009, compared with a loss related to hurricanes of $7.0 million for the same period in 2008.

Income tax benefit (expense). Income tax benefit totaled $60.1 million for 2009 compared to tax expense of $57.4 million for 2008, resulting in effective tax rates of 37.7 percent and 39.7 percent, respectively. The effective rate change from 2008 primarily reflected the impact of goodwill impairment in that year, but changes in the mix of the highest marginal state tax rates and differing effects of other permanent differences, including the

impact between years of the domestic production activities deduction and percentage depletion, also had an effect. Our current income tax benefit in 2009 was $20.4 million compared to current income tax expense of $19.2 million in 2008. These amounts were 34 percent and 33 percent, respectively, of the total income tax benefit or expense for each period. Our 2009 current income tax benefit reflected the creation of a net operating loss which we could carry back to one or more prior tax years to obtain a refund.

Overview of Liquidity and Capital Resources

In order to meet our projected growth targets, we will have to effectively invest capital into new projects and acquisitions. The following analysis and discussion includes our assessment of market risk and possible effects of inflation and changing prices.

Sources of cash

In 2011, we anticipate that cash flow from operations, the proceeds from our 6.625% Senior Notes, and expected divestiture and/or joint venture activity will fund the majority of our 2011 capital program. Our credit facility will be used to fund any remaining balance of our capital program for the year. Given the size of the commitments associated with our existing inventory of potential capital projects, our requirements for funding could increase significantly during 2011 and beyond. As a result, we may consider accessing the capital markets or using other financing alternatives as we determine how to best fund our capital program. We will continue to evaluate our property base to identify and divest of properties we consider non-core to our strategic goals.

Our primary sources of liquidity are the cash flows provided by our operating activities, use of our credit facility, divestitures of properties, and other financing alternatives, including accessing the capital and debt markets. From time to time, we may be able to enter into carrying cost funding and sharing arrangements with third parties for particular exploration and development programs. All of our sources of liquidity can be impacted by the general condition of the broad economy and by significant fluctuations in oil and gas prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, natural gas, or NGLs, although we are able to influence the amount of our net realized revenues related to our oil and gas sales through the use of derivative contracts. The borrowing base on our credit facility could be reduced as a result of lower commodity prices or divestitures of producing properties. Historically, decreases in commodity prices have limited our industry's access to the capital markets. Subsequent to year end, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. We do not anticipate the need to issue additional debt or equity in the near term, however these are options we would consider under the appropriate circumstances.

Current credit facility

On April 14, 2009, we entered into an amended $1.0 billion senior secured revolving credit facility with twelve participating banks. The initial borrowing base was set at $900 million. During September 2010 the lending group redetermined our reserve-based borrowing base under the credit facility at $1.1 billion. We have been provided a $678 million commitment amount by the bank group. We believe that the current commitment is sufficient to meet our current liquidity and operating needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 17 percent of the lending commitments under the credit facility. We monitor the credit environment closely and have frequent discussions with the lending group. Our credit facility expires on July 31, 2012, and we have begun discussions with the banks within the existing bank group, as well as banks not in the existing facility, about a new credit facility. Our intention is to have a new credit facility in place during the first half of 2011.

Pursuant to the terms of our credit facility our borrowing base was reduced by 25 percent of the $350.0 million of 6.625% Senior Notes issued, resulting in a new borrowing base of $1.0 billion. The next redetermination of our borrowing base is scheduled to occur in April 2011.

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We had no borrowings outstanding under this facility as of February 18, 2011. We had 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. We currently have $677.5 million of available borrowing capacity under this facility. Borrowings under our credit facility are secured by mortgages on substantially all of our oil and gas properties. Please refer to Note 5 — Long-term Debt in Part IV, Item 15 of this report for our borrowing base utilization grid.

The following table sets forth our weighted-average credit facility debt balance and weighted-average interest rate:

	For the Years Ended December 31,		
	2010	2009	2008
	(in millions)		
Weighted-average credit facility debt balance	$ 54.6	$ 275.4	$ 257.0
Weighted-average interest rate(1)	8.3%	5.4%	5.8%

(1) Includes the impact of our 3.50% Senior Convertible Notes.

Our weighted-average interest rates in the current and prior year include cash interest payments, cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs. The increase in our weighted-average interest rate from 2009 is the result of commitment fees and non-cash charges being spread across a much lower average outstanding credit facility debt balance.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to earnings before interest, taxes, depreciation, and amortization of less than 3.5 to 1.0 and a current ratio as defined by our credit agreement of not less than 1.0. As of December 31, 2010, our debt to EBITDA ratio and current ratio as defined by our credit agreement, were 0.67 and 2.05, respectively. We are in compliance with all financial and non-financial covenants under our credit facility.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties, and for the payment of debt obligations, trade payables, income taxes, common stock repurchases, stockholder dividends, and other general corporate purposes. During 2010, we spent $668.3 million for exploration and development capital expenditures. These amounts differ from the cost incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual-based activity upon which the costs incurred amounts are presented. These cash flows were funded using cash inflows from operations, proceeds from the sale of assets, and available borrowing capacity under our credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. The majority of our capital and exploration expenditures in 2011 will be funded with current year operating cash flows and the proceeds from the divestiture of assets and the issuance of our 6.625% Senior Notes. The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating, investing and financing activities, and our ability to assimilate acquisitions. In addition, the impact of oil and natural gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities may lead to changes in funding requirements for future development. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements, and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions,

privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws and other factors. The amounts involved in any such transaction may be material.

In 2010 we paid $6.3 million in dividends to our stockholders. Our current intention is to continue to make dividend payments for the foreseeable future, subject to our future earnings, our financial condition, possible credit facility, and other covenants, and other currently unexpected factors which could arise. 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.

As of the filing date of this report, we have authorization from our Board of Directors to repurchase up to 3,072,184 shares of our common stock under our stock repurchase program. 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 our credit facility and the indenture governing our 6.625% Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. There were no share repurchases in 2010.

Current proposals to fund the federal government budget include eliminating or reducing current tax deductions for intangible drilling costs, the domestic production activities deduction, and percentage depletion. Legislation modifying or eliminating these deductions would have the immediate effect of reducing operating cash flows thereby reducing funding available for our exploration and development capital programs and those of our peers in the industry. These funding reductions could have a significant adverse effect on drilling in the United States for a number of years.

The following table presents amounts and percentage changes between years in net cash flows from our operating, investing, and financing activities. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part IV, Item 15 of this report.

	Amount of Changes Between		Percent of Change Between	
	2010/2009	2009/2008	2010/2009	2009/2008
Change in net cash provided by operating activities	$ 60,991	$ (243,084)	14%	(36)%
Change in net cash used in investing activities	$ (57,481)	$ 369,662	19%	(55)%
Change in net cash used in financing activities	$ (13,600)	$ (84,681)	11%	198%

Analysis of cash flow changes between 2010 and 2009

Operating activities. Cash received from oil and gas production revenues, net of the realized effects of hedging, increased $84.6 million to $836.4 million for the year ended December 31, 2010. The increase was the result of a one percent increase in production and a 13 percent increase in our net realized price after hedging, resulting in a 14 percent increase in production revenue. Included in the 2010 oil and gas production revenue amounts is $23.5 million of net realized hedging gains. Additionally, cash paid for lease operating expenses decreased $29.2 million. We received $25.6 million in income tax refunds in 2010 compared to $9.9 million received during 2009.

Investing activities. Cash used for investing activities was $361.6 million for the year ended December 31, 2010, compared with $304.1 million for the same period in 2009. We received proceeds of $311.5 million primarily from the sale of non-strategic properties located in our Rocky Mountain and Permian regions, as discussed under *2010 Highlights* above. The $39.9 million proceeds from the sale of oil and gas properties received in 2009 related primarily to the sale of non-strategic properties located in the Rocky Mountain region that were divested of in the fourth quarter of 2009. Cash outflows for 2010 capital expenditures increased

$289.0 million, or 76 percent, to $668.3 million. This is due to increased drilling activity as a result of more favorable commodity prices, an improved overall macro-economic environment, and our drilling efforts in our Eagle Ford shale play. We received $16.8 million in proceeds from an insurance settlement relating to Hurricane Ike for the year ended December 31, 2009. There were no insurance proceeds received in 2010.

Financing activities. Net repayments to our credit facility increased $28.0 million for the year ended December 31, 2010, compared to 2009. We spent $11.1 million on debt issuance costs for our amended credit facility during the year ended December 31, 2009. We did not incur any debt issuance costs in 2010. We received $3.3 million more in proceeds from the sale of common stock in 2010, than in 2009.

We had $5.1 million in cash and cash equivalents and a working capital deficit of $227.4 million as of December 31, 2010, compared to $10.6 million in cash and cash equivalents and working capital deficit of $87.6 million as of December 31, 2009.

Analysis of cash flow changes between 2009 and 2008

Operating activities. Cash received from oil and gas production revenues, net of the realized effects of hedging, decreased $438.5 million to $751.8 million for the year ended December 31, 2009. The decrease was the result of a five percent decrease in production and a 31 percent decrease in our net realized price after hedging, resulting in a 35 percent decrease in production revenue. Included in the 2009 oil and gas production revenue amounts was $140.6 million of net realized hedging gains. We received $9.9 million in income tax refunds in 2009 compared to payments of $17.3 million during 2008.

Investing activities. Cash used for investing activities decreased $369.7 million for the year ended December 31, 2009, compared with the same period in 2008. Cash outflows for 2009 capital expenditures for development and exploration activities decreased $367.3 million or 49 percent to $379.3 million, which reflected a reduced level of activity as a result of lower commodity prices. Total cash outflow for 2009 related to the acquisition of oil and gas properties decreased $81.7 million or 100 percent to $76,000. We had no significant acquisitions of oil and gas properties in 2009, compared with the acquisition of Carthage Field properties during 2008. Proceeds from an insurance settlement relating to Hurricane Ike were $16.8 million for the year ended December 31, 2009, compared with the same period in 2008 when we received no proceeds from insurance settlements. Proceeds from the sale of oil and gas properties for the year ended December 31, 2009, decreased $139.0 million compared to the same period in 2008. Proceeds received in 2009 from the sale of oil and gas properties related to non-strategic properties located in the Rocky Mountain region that were divested of in the fourth quarter of 2009. The majority of the 2008 proceeds related to non-strategic properties sold in the first quarter of 2008.

Financing activities. Net repayments to our credit facility increased $127.0 million for the year ended December 31, 2009, compared to 2008. We spent $11.1 million on debt issuance costs for our amended credit facility during the year ended December 31, 2009. We did not incur any debt issuance costs during 2008. Our excess income tax benefit attributable to the exercise of stock awards decreased $13.9 million in the year ended December 31, 2009, compared with 2008. We received $8.8 million less in proceeds from the sale of common stock in 2009, than in 2008. Additionally, we invested $77.2 million less to repurchase shares of our common stock during 2009, than in 2008.

We had $10.6 million in cash and cash equivalents and a working capital deficit of $87.6 million as of December 31, 2009, compared to $6.1 million in cash and cash equivalents and working capital of $15.2 million as of December 31, 2008.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil and gas commodity prices and changes in interest rates. Changes in interest rates can affect the amount of interest we earn on our cash, cash equivalents, and short-term investments and the amount of interest we pay on borrowings under our revolving

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credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 3.50% Senior Convertible Notes, but do affect their fair market value.

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one percentage point parallel shift in the yield curve. For fixed-rate debt, interest changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value. We had $48.0 million of floating-rate debt outstanding as of December 31, 2010. Our fixed-rate debt outstanding, net of debt discount, at this same date was $275.7 million. As of December 31, 2010, we do not have any interest rate hedges in place to mitigate potential interest rate risks.

Since we produce and sell natural gas and crude oil, our financial results are affected when prices for these commodities fluctuate. The following table reflects our estimate of the effect on net cash flows from operations of a ten percent change in our average realized sales price for natural gas, for oil, and in combination for the years presented, inclusive of the impact of hedging. These amounts have been reduced by the effective income tax rate applicable to each period since a reduction in revenue would reduce cash requirements to pay income taxes. General and administrative expenses have not been adjusted. To fund the capital expenditures we incurred in those years we would have been required to utilize amounts under our credit facility as a source of funds. In each of these years we would have had sufficient unused borrowing capacity available under our credit facility to meet this contingency without reducing or eliminating expenditures or altering our growth strategy.

Pro forma effect on net cash flow from operations of a ten percent decrease in average realized sales price:

	For the Years Ended December 31,		
	2010	2009	2008
	(in thousands)		
Oil	$ 48,710	$ 29,523	$ 27,818
Natural Gas	30,455	11,874	37,288
Total	$ 79,165	$ 41,397	$ 65,106

We enter into hedging transactions in order to reduce the impact of fluctuations in commodity prices. Please refer to Note 10—Derivative Financial Instruments of Part IV, Item 15 of this report for additional information about our oil and gas derivative contracts, and additional information is below under the caption *Summary of Oil and Gas Production Hedges in Place.* We do not anticipate significant changes in existing hedge contracts or derivative contract transactions.

Summary of Oil and Gas Production Hedges in Place

Our oil and natural gas derivative contracts include swap and costless collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 10 — Derivative Financial Instruments in Part IV, Item 15 of this report for additional information regarding accounting for our derivative transactions. Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted production. Hedging is an important part of our financial risk management program. The amount of production we hedge is driven by the amount of debt on our consolidated balance sheet and the level of capital and long-term commitments we have made. In the case of a significant acquisition of producing properties, we will consider hedging a portion of the anticipated production in order to protect the economics assumed at the time of the acquisition. As of December 31, 2010, our hedged positions of anticipated production through the third quarter of 2013 totaled approximately 6 million Bbls of oil, 35 million MMBtu of natural gas, and 2 million Bbls of NGLs. As of February 18, 2011, the Company had hedge contracts in place through the fourth quarter of 2013 for a total of approximately 9 million Bbls of anticipated crude oil production, 44 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated NGL production.

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In a typical commodity swap agreement, if the agreed-upon published third-party index price is lower than the swap fixed price, we receive the difference between the index price per unit of production and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. We pay the difference between the agreed upon contracted ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

The following table describes the volumes, average contract prices, and fair value of contracts we have in place as of December 31, 2010. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX WTI prices and the majority of our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

Oil contracts

Oil Swaps:

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2010 Liability
	(Bbls)	(per Bbl)	(in thousands)
First quarter 2011	418,000	$ 70.36	$ 9,170
Second quarter 2011	367,800	$ 69.49	8,901

Third quarter 2011	327,800	$ 68.63	8,354
Fourth quarter 2011	325,400	$ 73.51	6,738
2012	1,514,200	$ 82.62	16,696
2013	294,600	$ 84.30	2,473
All oil swap contracts	3,247,800		$ 52,332

Oil Collars:

Contract Period	NYMEX WTI Volumes (Bbls)	Weighted-Average Floor Price (per Bbl)	Weighted-Average Ceiling Price (per Bbl)	Fair Value at December 31, 2010 Liability (in thousands)
First quarter 2011	305,250	$ 50.00	$ 63.70	$ 8,735
Second quarter 2011	308,250	$ 50.00	$ 63.70	9,334
Third quarter 2011	311,250	$ 50.00	$ 63.70	9,686
Fourth quarter 2011	311,250	$ 50.00	$ 63.70	9,783
2012	667,500	$ 72.45	$ 103.35	2,402
2013	1,176,300	$ 72.40	$ 103.55	4,431
All oil collars	3,079,800			$ 44,371

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Gas Contracts

Gas Swaps:

Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at December 31, 2010 Asset (in thousands)
First quarter 2011			
IF ANR OK	110,000	$ 6.56	$ 266
IF CIG	180,000	$ 6.38	417
IF El Paso	610,000	$ 6.93	1,738
IF HSC	360,000	$ 9.01	1,730
IF NGPL	260,000	$ 6.39	583
IF NNG Ventura	290,000	$ 6.77	691
IF PEPL	510,000	$ 6.44	1,182
IF Reliant	1,140,000	$ 6.36	2,528
IF TETCO STX	450,000	$ 6.97	1,238
NYMEX Henry Hub	510,000	$ 7.11	1,409
Second quarter 2011			
IF ANR OK	110,000	$ 5.74	173
IF CIG	210,000	$ 5.54	333
IF El Paso	520,000	$ 5.99	976
IF NGPL	220,000	$ 5.65	327
IF NNG Ventura	280,000	$ 6.02	477
IF PEPL	450,000	$ 5.59	655
IF Reliant	1,070,000	$ 5.63	1,529
IF TETCO STX	420,000	$ 6.52	926
NYMEX Henry Hub	810,000	$ 6.41	1,593
Third quarter 2011			
IF ANR OK	140,000	$ 5.92	227
IF CIG	340,000	$ 5.81	575
IF El Paso	330,000	$ 6.08	577
IF NGPL	290,000	$ 5.93	476
IF NNG Ventura	340,000	$ 6.14	597
IF PEPL	500,000	$ 5.90	806
IF Reliant	1,170,000	$ 6.06	2,052
IF TETCO STX	280,000	$ 5.96	421
NYMEX Henry Hub	390,000	$ 6.59	783
Fourth quarter 2011			
IF ANR OK	140,000	$ 6.21	223
IF CIG	300,000	$ 6.19	509
IF El Paso	320,000	$ 6.10	492
IF NGPL	270,000	$ 6.31	464
IF NNG Ventura	290,000	$ 6.53	499
IF PEPL	370,000	$ 6.23	645
IF Reliant	1,130,000	$ 6.42	2,069
IF TETCO STX	270,000	$ 6.31	426
NYMEX Henry Hub	420,000	$ 6.98	882

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Gas Swaps (continued)

Contract Period	Volumes (MMBtu)		Weighted-Average Contract Price (per MMBtu)	Fair Value at December 31, 2010 Asset (in thousands)
2012				
IF ANR OK	360,000	$	6.18	517
IF CIG	1,020,000	$	5.77	1,077
IF El Paso	850,000	$	6.04	1,047
IF NGPL	660,000	$	6.34	1,043
IF NNG Ventura	620,000	$	6.51	909
IF PEPL	2,730,000	$	6.25	4,136
IF Reliant	3,540,000	$	5.97	3,912
IF TETCO STX	660,000	$	6.30	880
2013				
IF PEPL	1,250,000	$	5.65	482
IF Reliant	1,290,000	$	5.64	489
All gas swap contracts	28,780,000			$ 45,986

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Gas Collars:

Contract Period	Volumes (MMBtu)		Weighted- Average Floor Price (per MMBtu)		Weighted- Average Ceiling Price (per MMBtu)		Fair Value at December 31, 2010 Asset (in thousands)
First quarter 2011							
IF CIG	450,000	$	5.00	$	6.32	$	457
IF HSC	120,000	$	5.57	$	6.77		160
IF PEPL	1,050,000	$	5.31	$	6.51		1,264
NYMEX Henry Hub	30,000	$	6.00	$	7.25		51
Second quarter 2011							
IF CIG	450,000	$	5.00	$	6.32		497
IF HSC	120,000	$	5.57	$	6.77		148
IF PEPL	1,055,000	$	5.31	$	6.51		1,296
NYMEX Henry Hub	30,000	$	6.00	$	7.25		48
Third quarter 2011							
IF CIG	450,000	$	5.00	$	6.32		457
IF HSC	120,000	$	5.57	$	6.77		141
IF PEPL	1,060,000	$	5.31	$	6.51		1,203
NYMEX Henry Hub	30,000	$	6.00	$	7.25		45
Fourth quarter 2011							
IF CIG	450,000	$	5.00	$	6.32		346
IF HSC	120,000	$	5.57	$	6.77		119
IF PEPL	1,060,000	$	5.31	$	6.51		1,039
NYMEX Henry Hub	30,000	$	6.00	$	7.25		38
All gas collars	6,625,000					$	7,309

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Natural Gas Liquid Contracts

Natural Gas Liquid Swaps:

	Volumes (approx. Bbls)		Weighted-Average Contract Price (per Bbl)		Fair Value at December 31, 2010 Liability (in thousands)
First quarter 2011	331,000	$	40.34	$	2,537
Second quarter 2011	302,000	$	39.43		1,607
Third quarter 2011	279,000	$	39.51		1,270
Fourth quarter 2011	260,000	$	39.55		1,241
2012	642,000	$	38.47		1,919
2013	84,000	$	44.95		287
All natural gas liquid swaps*	1,898,000			$	8,861

*Natural gas liquid swaps are comprised of OPIS Mont. Belvieu LDH Propane (28%), OPIS Mont. Belvieu Purity Ethane (46%), OPIS Mont. Belvieu NON-LDH Isobutane (4%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (12%), and OPIS Mont. Belvieu NON-LDH Normal Butane (10%).

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Hedge Contracts Entered into After December 31, 2010

The following tables include all hedges entered into subsequent to December 31, 2010 through February 18, 2011:

Oil Collars:

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
Second Quarter 2011	318,800	$ 80.00	$ 109.30
Third Quarter 2011	265,500	$ 80.00	$ 109.30
Fourth Quarter 2011	203,600	$ 80.00	$ 109.30
2012	767,100	$ 80.00	$ 115.40
2013	970,200	$ 80.00	$ 117.40
All oil collars	2,525,200		

Gas Swaps:

Contract Period	Volumes	Weighted- Average Contract Price
	(MMBtu)	(per MMBtu)
Fourth Quarter 2011		
IF HSC	529,000	$ 4.56
IF TETCO STX	691,000	$ 4.24
2012		
IF HSC	1,871,000	$ 4.56
IF TETCO STX	2,289,000	$ 4.54
2013		
IF TETCO STX	3,220,000	$ 4.88
All gas swap contracts	8,600,000	

Please see Note 10—Derivative Financial Instruments in Part IV, Item 15 of this report for additional information regarding our oil and gas hedges.

Schedule of Contractual Obligations

The following table summarizes our future estimated principal payments and minimum lease payments for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt	$ 348.1	$ 10.1	$ 338.0	$ —	$ —
Derivative liability	115.7	82.5	33.2	—	—
Net Profits Plan	133.8	22.1	46.6	43.8	21.3
Delivery commitments	181.1	4.8	33.8	41.6	100.9
Operating leases and contracts	227.2	101.9	82.7	23.9	18.7
Other	15.2	5.0	9.6	0.2	0.4
Total	$ 1,021.1	$ 226.4	$ 543.9	$ 109.5	$ 141.3

This table includes the remaining unfunded portion of our estimated pension liability of $13.5 million even though we recognize that we cannot accurately determine the timing of future payments. We are required to make a contribution to the Pension Plan in 2011 of $4.4 million. We made contributions of $1.7 million and $2.0 million in 2010 and 2009, respectively, towards our pension liability. The table also includes $133.8 million in other long-term liabilities that represents six years of undiscounted forecasted payments for the Net Profits Plan. Payments are expected to gradually decrease for the years beyond what is shown in this table. The amounts recorded on the consolidated balance sheets reflect all future Net Profits Plan payments and the impact of discounting and therefore differ from the amounts disclosed in this table. The variability in the amount of payments will be a direct reflection of commodity prices, production rates, capital expenditures, and operating costs in future periods. Predicting the timing and amounts of payments associated with this liability is contingent upon estimates of appropriate discount factors, adjusting for risk and time value, and upon a number of factors that we cannot control. The components of the operating leases are discussed in more detail in Note 6—Commitments and Contingencies of Part IV, Item 15 of this report.

The actual payments under our revolving credit facility will vary significantly. Our credit facility has a maturity date of July 31, 2012, and therefore for purposes of this table, the December 31, 2010, balance under our credit facility has been disclosed in the table under the heading 1-3 years. For purposes of this table, we have assumed we will net share settle the 3.50% Senior Convertible Notes in 2012. Accordingly, $12.6 million of interest payments related to the 3.50% Senior Convertible Notes are included in the long-term debt line in table above. We have excluded asset retirement obligations because we are not able to accurately predict the precise timing of these amounts. Pension liabilities, asset retirement obligations, and Net Profits Plan are discussed in Note 8—Pension Benefits, Note 9—Asset Retirement Obligations, and Note 7—Compensation Plans of Part IV, Item 15 of this report.

This table also includes estimated oil and natural gas derivative payments of $115.7 million based on future market prices as of December 31, 2010. This amount represents only the cash outflows; it does not include estimated oil and gas derivative receipts of $62.7 million that would be paid based on December 31, 2010, market prices. The net liability of $53.0 million represents cash flows from the intrinsic value of our collar arrangements and differs in amount from our recorded fair value, which as of December 31, 2010, was a net liability of $52.3 million. The fair value considers time value, volatility, and the risk of non-performance for us and for our counterparties. Both the intrinsic value and fair value will change as oil and natural gas commodity prices

change. Please refer to the discussion above under the caption *Summary of Oil and Gas Production Hedges in Place* and Note 10—Derivative Financial Instruments in Part IV, Item 15 of this report for additional information regarding our oil and gas hedges.

We believe that we will continue to pay annual dividends of $0.10 per share. We anticipate making cash payments for income taxes, dependent on net income and capital spending; however, 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.

Subsequent to year end, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. The 6.625% Senior Notes mature on February 15, 2019, and we will make annual interest payments of $23.2 million. Additionally, subsequent to year end we entered into a hydraulic fracturing services contract. The total commitment is $180.0 million over a two year term; provided however, our liability upon early termination of this contract may not exceed $24 million. These obligations are not reflected in the amounts above.

Off-balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of December 31, 2010, we have not been involved in any unconsolidated SPE transactions.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses as well as the disclosure of contingent assets and liabilities as of the date of our financial statements. We base our decisions affecting the estimates we use on historical experience and various other sources that are believed to be reasonable under the circumstances. Actual results may differ from the estimates we calculate due to changes in business conditions or due to unexpected circumstances. Policies we believe are critical to understanding our business operations and results of operations are detailed below. For additional information on our significant accounting policies, please refer to Note 1 — Summary of Significant Accounting Policies, Note 9—Asset Retirement Obligations, and Note 15—Disclosures about Oil and Gas Producing Activities in Part IV, Item 15 of this report.

Proved oil and gas reserve quantities. Estimated reserve quantities and the related estimates of future net cash flows are critical estimates for our company because they affect the perceived value of an exploration and production company. Additionally, they are used in comparative financial analysis ratios and are used as the basis for the most significant accounting estimates in our financial statements. Those significant accounting estimates include the periodic calculations of depletion, depreciation, and impairment of our proved oil and gas properties and the estimates of our liability for future payments under the Net Profits Plan. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved oil and gas reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using a discount rate that depends upon the purpose for which the reserve estimates will be used. For example, the standardized measure calculations require a ten percent discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves, including using independent reserve engineering consultants. We expect that periodic reserve

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estimates will change in the future as additional information becomes available and as oil and gas prices and operating and capital costs change. We evaluate and estimate our proved oil and gas reserves at December 31 and June 30 of each year. For purposes of depletion, depreciation, and impairment, reserve quantities are adjusted at all interim periods for the estimated impact of additions and dispositions. Changes in depletion, depreciation, or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period the reserve estimates change.

The following table presents information regarding reserve changes from period to period that reflect changes from items we do not control, such as price, and from changes resulting from better information due to production history, and from well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Years Ended December 31,		
	2010	2009	2008
	BCFE Change	BCFE Change	BCFE Change
Revisions resulting from price changes	42.6	12.0	(199.7)
Revisions resulting from performance	(17.9)	(61.6)	(44.5)
Total	24.7	(49.6)	(244.2)

We have added 424.1 BCFE of reserves over a three-year period, excluding divestitures. A 124.0 BCFE decrease in reserves was a result of changes in engineering estimates based on the performance of our oil and gas properties. A 145.1 BCFE decrease in reserves was a result of price changes. As previously noted, oil and gas prices are volatile, and estimates of reserves are inherently imprecise. Consequently, we anticipate we may continue to experience these types of changes.

The following table reflects the estimated BCFE change and percentage change to our total reported reserve volumes from the described hypothetical changes:

	For the Years Ended December 31,					
	2010		2009		2008	
	BCFE Change	Percentage Change	BCFE Change	Percentage Change	BCFE Change	Percentage Change
A 10% decrease in pricing	(13.9)	(1)%	(25.1)	(3)%	(120.8)	(14)%
A 10% decrease in proved undeveloped reserves	(29.7)	(3)%	(14.2)	(2)%	(15.0)	(2)%

Additional reserve information can be found in the reserve table and discussion included in Items 1 and 2 of Part I of this report.

Successful efforts method of accounting. Generally accepted accounting principles provide for two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method. Both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities, and a detailed description is included in Note 1 of Part IV, Item 15 of this report.

Revenue recognition. Our revenue recognition policy is significant because revenue is a key component of our results of operations and our forward-looking statements contained in our analysis of liquidity and capital resources. We derive our revenue primarily from the sale of produced natural gas, natural gas liquids, and crude oil. We report revenue as the gross amounts we receive before taking into account production taxes and

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transportation costs, which are reported as separate expenses. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, NYMEX and local spot market prices, and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A ten percent change in our year end revenue accrual would have impacted net income before tax by approximately $10.8 million in 2010.

Crude oil and natural gas hedging. Through December 31, 2010, our crude oil and natural gas hedging contracts were intended to and usually did qualify for cash flow deferral hedge accounting. Under this guidance a majority of the gain or loss from a contract qualified as a cash flow hedge was deferred from recognition in the consolidated statement of operations. The realized gain or loss reflected in the consolidated statement of operations was based on actual hedge contract settlements. Effective January 1, 2011, we elected to de-designate all of our commodity hedges that had previously been designated as cash flow hedges as of December 31, 2010. We also elected to discontinue hedge accounting prospectively. As a result, our periodic consolidated statements of operations could include significant changes in the estimate of non-cash derivative gain or loss due to swings in the value of these contracts. Consequently, we would report a different amount of oil and gas hedge loss in our statements of operations. These fluctuations could be especially significant in a volatile pricing environment such as what we have encountered over the last few years. The amounts recorded to accumulated other comprehensive income (loss) of $23.5 million of income, $103.3 million of loss, and $223.5 million of income for 2010, 2009, and 2008, respectively, would have increased or decreased net income after tax if our hedges did not qualify as cash flow hedges.

Change in Net Profits Plan Liability. We record the estimated liability of future payments for our Net Profits Plan. The estimated liability is calculated based on a number of assumptions, including estimates of proved oil and gas reserves, recurring and workover lease operating expense, production and ad valorem tax rates, present value discount factors, and pricing assumptions. Additional discussion is included in the analysis in the above section titled *2010 Highlights* under the heading *Net Profits Plan.* In 2008 the Net Profits Plan was replaced with a long-term equity incentive program. As a result, the 2007 Net Profits Plan pool was the last pool established.

Asset retirement obligations. We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells projected into the future based on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates, and determine what credit adjusted risk-free rate discount to use. The impact to the consolidated statement of operations from these estimates is reflected in our depreciation, depletion, and amortization calculations and occurs over the remaining life of our respective oil and gas properties.

Valuation of long-lived and intangible assets. Our property and equipment are recorded at cost. An impairment allowance is provided on unproven property when we determine that the property will not be developed or the carrying value will not be realized. We evaluate the realizability of our proved properties and other long-lived assets whenever events or changes in circumstances indicate that impairment may be appropriate. Our impairment test compares the expected undiscounted future net revenues from property, using escalated pricing, with the related net capitalized cost of the property at the end of each period. When the net capitalized costs exceed the undiscounted future net revenue of a property, the cost of the property is written down to its estimate of fair value, which is determined by applying a discount rate we believe is indicative of the current market. Our criteria for an acceptable internal rate of return are subject to change over time. Different pricing assumptions or discount rates could result in a different calculated impairment. We recorded a $6.1 million impairment of proved oil and gas properties in 2010, compared with $174.8 million impairment of proved oil and gas properties in 2009. A significant decrease in commodity prices and increase in differentials during the first quarter of 2009 caused the majority of the non-cash impairment. The largest portion of the impairment in 2009

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was $97.3 million related to assets located in the Mid-Continent region that were significantly impacted by lower prices and wider than normal differentials.

Income taxes. We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared, therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we use and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement could have an impact on our results of operations. A one percent change in our effective tax rate would have changed our calculated income tax expense by $3.1 million for the year ended December 31, 2010.

Accounting Matters

Please refer to the section entitled *Recently Issued Accounting Standards* under Note 1—Summary of Significant Accounting Policies for additional information on the recent adoption of new authoritative accounting guidance in Part IV, Item 15 of this report.

Environmental

SM Energy’s compliance with applicable environmental laws and regulations has to date not resulted in significant capital expenditures or material adverse effects on our liquidity or results of operations. We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic fracturing. 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 environmental 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.”

Climate Change. 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 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 and natural gas we produced. 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.

In terms of opportunities, the regulation of greenhouse gas emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways. For example, although climate change legislation could reduce the overall demand for the oil and natural gas that we produce, the relative demand for natural gas may increase since the burning of natural gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources, such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, natural gas may become a more attractive transportation fuel. In both 2009 and 2010, approximately 65 percent of our production was natural gas on an MCFE basis. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and natural gas reservoirs, could also benefit us through the potential to obtain greenhouse gas emission allowances or offsets from or government incentives for the sequestration of carbon dioxide.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions "*Commodity Price Risk and Interest Rate Risk*" and "*Summary of Oil and Gas Production Hedges in Place*" in Item 7 above and is incorporated herein by reference.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The Consolidated Financial Statements that constitute Item 8 follow the text of this report. An index to the Consolidated Financial Statements and Schedules appears in Item 15(a) of this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this Annual Report on Form 10-K. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective for the purpose discussed above as of the end of the period covered by this Annual Report on Form 10-K. There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Stockholders' of SM Energy Company

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Company's internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that have a material effect on the financial statements.

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control—Integrated Framework.*

Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2010.

The Company's independent registered public accounting firm has issued an attestation report on the Company's internal controls over financial reporting. That report immediately follows this report.

/s/ ANTHONY J. BEST
Anthony J. Best
President and Chief Executive Officer
February 25, 2011

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial Officer
February 25, 2011

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SM Energy Company and Subsidiaries
Denver, Colorado

We have audited the internal control over financial reporting of SM Energy Company and subsidiaries (the "Company") as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2010, of the Company and our report dated February 25, 2011, expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding the Company's adoption of new accounting guidance.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 25, 2011

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item concerning SM Energy's Directors and corporate governance is incorporated by reference to the information provided under the captions "Structure of the Board of Directors," "Proposal 1—Election of Directors," and "Corporate Governance" in SM Energy's definitive proxy statement for the 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010. The information required by the Item concerning SM Energy's executive officers is incorporated by reference to the information provided in Part I—EXECUTIVE OFFICERS OF THE REGISTRANT, included in this Form 10-K.

The information required by this Item concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the information provided under the caption "Section 16(a) Beneficial Ownership Reporting Compliance" in SM Energy's definitive proxy statement for the 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions, "Executive Compensation" and "Director Compensation" in SM Energy's definitive proxy statement for the 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption "Security Ownership of Certain Beneficial Owners and Management" in SM Energy's definitive proxy statement for the 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

The information required by this Item concerning securities authorized for issuance under equity compensation plans is incorporated by reference to the information provided under the caption "Equity Compensation Plans" in Part II, Item 5—Market for Registrant's Common Equity, Related Stockholder Matter and Issuer Purchases of Equity Securities, included in this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information provided under the caption "Certain Relationships and Related Transactions," and "Corporate Governance," in SM Energy's definitive proxy statement for the 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the information provided under the caption "Independent Accountants" and "Audit Committee Preapproval Policy and Procedures" in SM Energy's definitive proxy statement for the 2011 annual meeting of stockholders to be filed within 120 days from December 31, 2010.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
2.1	Purchase and Sale Agreement dated December 11, 2007, among St. Mary Land & Exploration Company, Ralph H. Smith Restated Revocable Trust Dated 8/14/97, Ralph H. Smith Trustee, Kent. J. Harrell, Trustee of the Kent J. Harrell Revocable Trust Dated January 19, 1995, and Abraxas Operating LLC (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on February 1, 2008, and incorporated herein by reference)
2.2	Ratification and Joinder Agreement dated January 31, 2008, among St. Mary Land & Exploration Company, Ralph H. Smith, Kent J. Harrell, Abraxas Operating, LLC and Abraxas Petroleum Corporation (filed as Exhibit 2.2 to the registrant's Current Report on Form 8-K filed on February 1, 2008, and incorporated herein by reference)
2.3	Purchase and Sale Agreement dated December 17, 2009 and effective as of November 1, 2009, between Legacy Reserves Operating LP and St. Mary Land & Exploration Company (filed as Exhibit 2.5 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2009 and incorporated herein by reference)

2.4	Purchase and Sale Agreement dated January 7, 2010 and effective as of November 1, 2009, between Sequel Energy Partners LP, Bakken Energy Partners, LLC, Three Forks Energy Partners, LLC and St. Mary Land & Exploration Company (filed as Exhibit 2.6 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2009 and incorporated herein by reference)

3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
3.2	Restated By-Laws of SM Energy Company amended effective as of June 1, 2010 (filed as Exhibit 3.2 to the registrant's Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)
4.1	Shareholder Rights Plan adopted on July 15, 1999 (filed as Exhibit 4.1 to the registrant's Quarterly Report on Form 10-Q/A for the quarter ended June 30, 1999 and incorporated herein by reference)
4.2	First Amendment to Shareholders Rights Plan dated March 15, 2002 as adopted by the Board of Directors on July 19, 2001 (filed as Exhibit 4.2 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2001 and incorporated herein by reference)
4.3	Second Amendment to Shareholder Rights Plan dated April 24, 2006 (filed as Exhibit 4.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006 and incorporated herein by reference)
4.4	Indenture related to the 3.50% Senior Convertible Notes due 2027, dated as of April 4, 2007, between St. Mary Land & Exploration Company and Wells Fargo Bank, National Association, as trustee (including the form of 3.50% Senior Convertible Note due 2027) (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on April 4, 2007 and incorporated herein by reference)
4.5	Registration Rights Agreement, dated as of April 4, 2007, among St. Mary Land & Exploration Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wachovia Capital Markets, LLC, for themselves and as representatives of the Initial Purchasers (filed Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on April 4, 2007, and incorporated herein by reference)
4.6	Indenture related to the 6.625% Senior Notes due 2019, dated as of February 7, 2011, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on February 10, 2011, and incorporated herein by reference)
4.7	Registration Rights Agreement, dated as of February 7, 2011, by and among SM Energy Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities, LLC, as representatives of the several initial purchasers (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on February 10, 2011, and incorporated herein by reference)
10.1†	Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.1 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.2†	Incentive Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.2 to the registrant's Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.3†	Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference)
10.4†	Form of Amendment to Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.9 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30,

	2005 and incorporated herein by reference)
10.5†	Employment Agreement of A.J. Best dated May 1, 2006 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 4, 2006 and incorporated herein by reference)
10.6†	Form of Performance Share Award Agreement (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q filed on August 5, 2008 and incorporated herein by reference)
10.7†	Form of Performance Share Award Notice (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q filed on August 5, 2008 and incorporated herein by reference)
10.8	Third Amended and Restated Credit Agreement dated April 14, 2009 among St. Mary Land & Exploration Company, Wachovia Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.9	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.10	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant's Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.11†	Equity Incentive Compensation Plan as Amended and Restated as of March 26, 2009 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 27, 2009, and incorporated herein by reference)
10.12†	Equity Incentive Compensation Plan As Amended and Restated as of April 1, 2010 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)
10.13♦	SM Energy Company Equity Incentive Compensation Plan, As Amended as of July 30, 2010 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.14†	Form of Performance Share and Restricted Stock Unit Award Agreement (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, and incorporated herein by reference)
10.15†	Form of Performance Share and Restricted Stock Unit Award Notice (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, and incorporated herein by reference)
10.16†	Third Amendment to Employee Stock Purchase Plan dated September 23, 2009 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, and incorporated herein by reference)
10.17†	Fourth Amendment to Employee Stock Purchase Plan dated December 29, 2009 (filed as Exhibit 10.46 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference)
10.18♦	Employee Stock Purchase Plan, As Amended and Restated as of July 30, 2010 (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)

10.19	Carry and Earning Agreement between St. Mary Land & Exploration Company and Encana Oil & Gas (USA) Inc. executed as of April 29, 2010 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.20†	Form of Performance Share and Restricted Stock Unit Award Agreement as of July 1, 2010 (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.21†	Form of Performance Share and Restricted Stock Unit Award Notice as of July 1, 2010 (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.22†	Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.23***	Gas Services Agreement effective as of July 1, 2010 between SM Energy Company and Eagle Ford Gathering LLC (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.24♦	Cash Bonus Plan, As Amended on July 30, 2010 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.25♦	Net Profits Interest Bonus Plan, As Amended by the Board of Directors on July 30, 2010 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.26♦	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan, As Amended as of July 30, 2010 (filed as Exhibit 10.8 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.27†	Form of Amendment to Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 29, 2010, and incorporated herein by reference)
10.28*†	Amendment to A.J. Best Employment Agreement dated December 31, 2010
10.29	Purchase Agreement, dated January 31, 2011, among SM Energy Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities, LLC, as representatives of the Initial Purchasers named therein (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on February 1, 2011, and incorporated herein by reference)
10.30*	Pension Plan for Employees of SM Energy Company as Amended and Restated as of January 1, 2010
10.31*+	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan as Amended as of November 9, 2010
10.32*†	Summary of Compensation Arrangements for Non-Employee Directors
21.1*	Subsidiaries of Registrant
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Ryder Scott Company L.P.

23.3*	Consent of Netherland, Sewell & Associates, Inc.
24.1*	Power of Attorney
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Ryder Scott Audit Letter
101.INS****	XBRL Instance Document
101.SCH****	XBRL Schema Document
101.CAL****	XBRL Calculation Linkbase Document
101.LAB****	XBRL Label Linkbase Document
101.PRE****	XBRL Presentation Linkbase Document
101.DEF****	XBRL Taxonomy Extension Definition Linkbase Document

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- * Filed with this Form 10-K
- ** Furnished with this Form 10-K
- *** Certain portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934.
- **** Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.
- † Exhibit constitutes a management contract or compensatory plan or agreement.
- ♦ Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on July 30, 2010 primarily to reflect the recent change in the name of the registrant from St. Mary Land & Exploration Company to SM Energy Company. There were no material changes to the substantive terms and conditions in this document.
- + Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on November 9, 2010, in order to make technical revisions to ensure compliance with Section 409A of the Internal Revenue Code. There were no material changes to the substantive terms and conditions in this document.

(c) Financial Statement Schedules. See Item 15(a) above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SM Energy Company and Subsidiaries
Denver, Colorado

We have audited the accompanying consolidated balance sheets of SM Energy Company and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of SM Energy Company and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of oil and gas reserve estimation and related required disclosures in 2009 with the implementation of new accounting guidance.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 25, 2011, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 25, 2011

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PART II. FINANCIAL INFORMATION
ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except share amounts)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 5,077	$ 10,649
Accounts receivable (note 2)	163,190	116,136
Refundable income taxes	8,482	32,773
Prepaid expenses and other	45,522	14,259
Derivative asset	43,491	30,295
Deferred income taxes	8,883	4,934
Total current assets	274,645	209,046
Property and equipment (successful efforts method), at cost:		
Land	1,491	1,371
Proved oil and gas properties	3,389,158	2,797,341
Less—accumulated depletion, depreciation, and amortization	(1,326,932)	(1,053,518)
Unproved oil and gas properties	94,290	132,370
Wells in progress	145,327	65,771
Materials inventory, at lower of cost or market	22,542	24,467
Oil and gas properties held for sale (note 3)	86,811	145,392
Other property and equipment, net of accumulated depreciation of $15,480 in 2010 and $14,550 in 2009	21,365	14,404
	2,434,052	2,127,598
Other noncurrent assets:		
Derivative asset	18,841	8,251
Other noncurrent assets	16,783	16,041
Total other noncurrent assets	35,624	24,292
Total Assets	**$ 2,744,321**	**$ 2,360,936**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 2)	$ 417,654	$ 236,242
Derivative liability	82,044	53,929
Deposit associated with oil and gas properties held for sale	2,355	6,500
Total current liabilities	502,053	296,671
Noncurrent liabilities:		
Long-term credit facility	48,000	188,000
Senior convertible notes, net of unamortized discount of $11,827 in 2010, and $20,598 in 2009	275,673	266,902
Asset retirement obligation	69,052	60,289
Asset retirement obligation associated with oil and gas properties held for sale	2,119	18,126
Net Profits Plan liability	135,850	170,291

Deferred income taxes	443,135	308,189
Derivative liability	32,557	65,499
Other noncurrent liabilities	17,356	13,399
Total noncurrent liabilities	1,023,742	1,090,695
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value—authorized: 200,000,000 shares; issued: 63,412,800 shares in 2010 and 62,899,122 shares in 2009; outstanding, net of treasury shares: 63,310,165 shares in 2010 and 62,772,229 shares in 2009	634	629
Additional paid-in capital	191,674	160,516
Treasury stock, at cost: 102,635 shares in 2010 and 126,893 shares in 2009	(423)	(1,204)
Retained earnings	1,042,123	851,583
Accumulated other comprehensive loss	(15,482)	(37,954)
Total stockholders' equity	1,218,526	973,570
Total Liabilities and Stockholders' Equity	**$ 2,744,321**	**$ 2,360,936**

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the Years Ended December 31, 2010	2009	2008
Operating revenues and other income:			
Oil and gas production revenue	$ 836,288	$ 615,953	$ 1,259,400
Realized oil and gas hedge gain (loss)	23,465	140,648	(101,096)
Gain on divestiture activity (note 3)	155,277	11,444	63,557
Marketed gas system revenue	70,110	58,459	77,350
Other revenue	7,694	5,697	2,090
Total operating revenues and other income	1,092,834	832,201	1,301,301
Operating expenses:			
Oil and gas production expense	195,075	206,800	271,355
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	336,141	304,201	314,330
Exploration	63,860	62,235	60,121
Impairment of proved properties	6,127	174,813	302,230
Abandonment and impairment of unproved properties	1,986	45,447	39,049
Impairment of materials inventory	—	14,223	—
Impairment of goodwill	—	—	9,452
General and administrative	106,663	76,036	79,503
Bad debt expense (recovery)	—	(5,189)	16,735
Change in Net Profits Plan liability	(34,441)	(7,075)	(34,040)
Marketed gas system expense	66,726	57,587	72,159
Unrealized derivative (gain) loss	8,899	20,469	(11,209)
Other expense	3,027	13,489	10,415
Total operating expenses	754,063	963,036	1,130,100
Income (loss) from operations	338,771	(130,835)	171,201
Nonoperating income (expense):			
Interest income	321	227	485
Interest expense	(24,196)	(28,856)	(26,950)
Income (loss) before income taxes	314,896	(159,464)	144,736
Income tax benefit (expense)	(118,059)	60,094	(57,388)
Net income (loss)	**$ 196,837**	**$ (99,370)**	**$ 87,348**
Basic weighted-average common shares outstanding	62,969	62,457	62,243
Diluted weighted-average common shares outstanding	64,689	62,457	63,133
Basic net income (loss) per common share	**$ 3.13**	**$ (1.59)**	**$ 1.40**
Diluted net income (loss) per common share	**$ 3.04**	**$ (1.59)**	**$ 1.38**

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(In thousands, except share amounts)

	Common Stock		Additional Paid-in Capital	Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
	Shares	Amount		Shares	Amount			
Balances, January 1, 2008	**64,010,832**	**$ 640**	**$ 211,913**	**(1,009,712)**	**$ (29,049)**	**$ 876,038**	**$ (156,968)**	**$ 902,574**
Comprehensive income, net of tax:								
Net income	—	—	—	—	—	87,348	—	87,348
Change in derivative instrument fair value	—	—	—	—	—	—	177,005	177,005
Reclassification to earnings	—	—	—	—	—	—	46,463	46,463
Minimum pension liability adjustment	—	—	—	—	—	—	(1,207)	(1,207)
Total comprehensive income								309,609
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,186)	—	(6,186)
Treasury stock purchases	—	—	—	(2,135,600)	(77,150)	—	—	(77,150)
Retirement of treasury stock	(2,945,212)	(29)	(103,237)	2,945,212	103,266	—	—	—
Issuance of common stock under Employee Stock Purchase Plan	45,228	—	1,055	—	—	—	—	1,055
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings	482,602	5	(6,910)	—	—	—	—	(6,905)
Sale of common stock, including income tax benefit of stock option exercises	868,372	9	24,691	—	—	—	—	24,700
Stock-based compensation expense	3,750	—	13,771	23,113	1,041	—	—	14,812
Balances, December 31, 2008	**62,465,572**	**$ 625**	**$ 141,283**	**(176,987)**	**$ (1,892)**	**$ 957,200**	**$ 65,293**	**$ 1,162,509**
Comprehensive loss, net of tax:								
Net loss	—	—	—	—	—	(99,370)	—	(99,370)
Change in derivative instrument fair value	—	—	—	—	—	—	(35,977)	(35,977)
Reclassification to earnings	—	—	—	—	—	—	(67,344)	(67,344)
Minimum pension liability adjustment	—	—	—	—	—	—	74	74
Total comprehensive loss								(202,617)
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,247)	—	(6,247)
Issuance of common stock under Employee Stock Purchase Plan	86,308	1	1,515	—	—	—	—	1,516
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income tax cost of RSUs	156,252	1	(1,951)	—	—	—	—	(1,950)
Sale of common stock, including income tax benefit of stock option exercises	189,740	2	1,592	—	—	—	—	1,594
Stock-based compensation expense	1,250	—	18,077	50,094	688	—	—	18,765
Balances, December 31, 2009	**62,899,122**	**$ 629**	**$ 160,516**	**(126,893)**	**$ (1,204)**	**$ 851,583**	**$ (37,954)**	**$ 973,570**
Comprehensive income, net of tax:								
Net income	—	—	—	—	—	196,837	—	196,837
Change in derivative instrument fair value	—	—	—	—	—	—	16,811	16,811
Reclassification to earnings	—	—	—	—	—	—	6,641	6,641
Minimum pension liability adjustment	—	—	—	—	—	—	(980)	(980)
Total comprehensive income								219,309
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,297)	—	(6,297)
Issuance of common stock under Employee Stock Purchase Plan	52,948	1	1,669	—	—	—	—	1,670
Issuance of common stock upon settlement of RSUs following expiration of restriction period, net of shares used for tax withholdings, including income tax cost of RSUs	113,103	1	(2,094)	—	—	—	—	(2,093)
Sale of common stock, including income tax benefit of stock option exercises	346,377	3	5,621	—	—	—	—	5,624
Stock-based compensation expense	1,250	—	25,962	24,258	781	—	—	26,743
Balances, December 31, 2010	**63,412,800**	**$ 634**	**$ 191,674**	**(102,635)**	**$ (423)**	**$ 1,042,123**	**$ (15,482)**	**$ 1,218,526**

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

SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Years Ended December 31,		
	2010	2009	2008
Cash flows from operating activities:			

Net income (loss)	$ 196,837	$ (99,370)	$ 87,348
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Gain on divestiture activity	(155,277)	(11,444)	(63,557)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	336,141	304,201	314,330
Exploratory dry hole expense	289	7,810	6,823
Impairment of proved properties	6,127	174,813	302,230
Abandonment and impairment of unproved properties	1,986	45,447	39,049
Impairment of materials inventory	—	14,223	—
Impairment of goodwill	—	—	9,452
Stock-based compensation expense	26,743	18,765	14,812
Bad debt expense (recovery)	—	(5,189)	16,735
Change in Net Profits Plan liability	(34,441)	(7,075)	(34,040)
Unrealized derivative (gain) loss	8,899	20,469	(11,209)
Loss related to hurricanes	—	8,301	6,980
Loss on insurance settlement	—	—	2,296
Amortization of debt discount and deferred financing costs	13,464	12,213	9,344
Deferred income taxes	114,517	(39,735)	38,164
Plugging and abandonment	(8,314)	(26,396)	(9,168)
Other	(3,993)	3,382	3,875
Changes in current assets and liabilities:			
Accounts receivable	(47,153)	46,743	(14,327)
Refundable income taxes	24,291	(19,612)	(12,228)
Prepaid expenses and other	(35,363)	(6,626)	(1,504)
Accounts payable and accrued expenses	53,198	(4,814)	(12,348)
Excess income tax benefit from the exercise of stock awards	(854)	—	(13,867)
Net cash provided by operating activities	**497,097**	**436,106**	**679,190**
Cash flows from investing activities:			
Net proceeds from sale of oil and gas properties	311,504	39,898	178,867
Proceeds from insurance settlement	—	16,789	—
Capital expenditures	(668,288)	(379,253)	(746,586)
Acquisition of oil and gas properties	(664)	(76)	(81,823)
Receipts from (deposits to) restricted cash	—	14,398	(14,398)
Other	(4,125)	4,152	(9,814)
Net cash used in investing activities	**(361,573)**	**(304,092)**	**(673,754)**
Cash flows from financing activities:			
Proceeds from credit facility	571,559	2,072,500	2,571,500
Repayment of credit facility	(711,559)	(2,184,500)	(2,556,500)
Debt issuance costs related to credit facility	—	(11,074)	—
Proceeds from sale of common stock	6,440	3,110	11,888
Repurchase of common stock	—	—	(77,202)
Dividends paid	(6,297)	(6,247)	(6,186)
Excess income tax benefit from the exercise of stock awards	854	—	13,867
Other	(2,093)	(1,285)	(182)
Net cash used in financing activities	**(141,096)**	**(127,496)**	**(42,815)**
Net change in cash and cash equivalents	(5,572)	4,518	(37,379)
Cash and cash equivalents at beginning of period	10,649	6,131	43,510
Cash and cash equivalents at end of period	**$ 5,077**	**$ 10,649**	**$ 6,131**

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

Supplemental schedule of additional cash flow information and noncash investing and financing activities:

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands)		
Cash paid for interest	$ 13,340	$ 17,884	$ 21,976
Cash paid (refunded) for income taxes	$ (25,578)	$ (9,857)	$ 17,326

For the years ended December 31, 2010, 2009 and 2008, $238.5 million, $109.0 million, $116.5 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

For the years ended December 31, 2010, 2009, and 2008, the Company issued 24,258, 50,094, and 23,113 shares, respectively, of common stock from treasury to its non-employee directors pursuant to the Company's Equity Incentive Compensation Plan. The Company recorded compensation expense related to these issuances of approximately $781,000, $688,000, and $1.0 million for the years ended December 31, 2010, 2009, and 2008, respectively.

For the years ended December 31, 2010, 2009, and 2008, the Company issued 160,381, 215,700, and 678,197 of common stock upon the settlement of RSU's relating to awards granted in previous years. The Company and a majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholding as provided for in the plan documents and award agreements. As a result, the Company issued 113,103, 156,252, and 482,602 net shares of common stock associated with these grants for the years ended December 31, 2010, 2009, and 2008, respectively. The remaining 47,278, 59,448, and 195,595 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSU's.

In December 2008 the Company closed a transaction whereby it exchanged non-core oil and gas properties located in Coupee Parish, Louisiana fair valued at $30.4 million for an increased interest in properties located in Upton and Midland Counties, Texas and $17.6 million in cash.

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

SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Summary of Significant Accounting Policies

Description of Operations

SM Energy Company ("SM Energy" or the "Company"), formerly named St. Mary Land & Exploration Company, is 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.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States and the instructions to Form 10-K and regulation S-X. Subsidiaries that are not wholly-owned are accounted for using the equity or cost methods as appropriate. Equity method investments are included in other noncurrent assets in the accompanying consolidated balance sheets. Intercompany accounts and transactions have been eliminated. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2010, through the filing date of this report.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of proved oil and gas reserve quantities provide the basis for the calculation of depletion, depreciation, and amortization ("DD&A"), impairment of proved properties, asset retirement obligations, and the Net Profits Plan liability, each of which represents a significant component of the accompanying consolidated financial statements.

Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Accounts Receivable and Concentration of Credit Risk

The Company's accounts receivables consist mainly of receivables from oil and gas purchasers and from partners with interests in common properties operated by the Company. Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. The Company records an allowance for doubtful accounts on a case-by-case basis once there is evidence that collection is not probable. Receivables are not collateralized. As of December 31, 2010, and 2009, the Company had no allowance for doubtful accounts recorded.

The Company has accounts in the following locations under two national banks: Denver, Colorado; Shreveport, Louisiana; Houston, Texas; Midland, Texas; and Billings, Montana. The Company has accounts with local banks in Tulsa, Oklahoma and Billings, Montana. The Company's policy is to invest in highly-rated instruments and to limit the amount of credit exposure at each individual institution.

The Company currently uses eight separate counterparties for its oil and gas commodity derivatives. The counterparties to the Company's derivative instruments are highly-rated entities with corporate credit ratings at or

exceeding BBB+ and Baa1 classifications by Standard & Poor's and Moody's, respectively. Ratings represent minimum investment grade ratings.

Oil and Gas Producing Activities

The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures within the accompanying consolidated statements of cash flows. The costs of development wells are capitalized whether those wells are successful or unsuccessful.

Geological and geophysical costs and the costs of carrying and retaining unproved properties are expensed as incurred. DD&A of capitalized costs related to proved oil and gas properties is calculated on a pool-by-pool basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. As of December 31, 2010, and 2009, the Company's estimated salvage value was $67.9 million and $77.8 million, respectively.

In December 2008 the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the Petroleum Resource Management System, which was developed by several petroleum industry organizations and is a widely accepted standard for the management of petroleum resources. Key revisions include a requirement to use 12-month average pricing determined by averaging the first of the month prices for the preceding 12 months rather than year-end pricing for estimating proved reserves, the ability to include nontraditional resources in reserves, the ability to use new technology for determining proved reserves, and permitting disclosure of probable and possible reserves. The Company adopted these new rules and interpretations as of December 31, 2009.

Impairment of Proved and Unproved Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value, which is expected future discounted cash flows, when there is an indication that the carrying costs may not be recoverable. Expected future cash flows are calculated on all proved reserves using a discount rate and price forecasts selected by the Company's management. The discount rate is a rate that management believes is representative of current market conditions. The price forecast is based on NYMEX strip pricing for the first five years, adjusted for basis differentials. At the end of the first five years a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. An impairment write down is recorded on unproved property when the Company determines that either the property will not be developed or the carrying value is not realizable.

For the years ended December 31, 2010, 2009, and 2008, the Company recorded proved property impairment expense of $6.1 million, $174.8 million, and $302.2 million, respectively. In 2009, the Company incurred impairment on proved properties of $97.3 million related to assets located in our Mid-Continent region due to a significant decrease in the market price for natural gas and wider than normal differentials, $20.4 million related to assets located in our ArkLaTex region due to decreased natural gas prices and engineering revisions, and $14.0 million related to the write-down of certain assets located in the Gulf of Mexico in which the Company relinquished its ownership interests in order to satisfy its abandonment obligations. Approximately $154.0 million of the 2008 impairment write-down relates to the Olmos assets in South Texas that were acquired as part of the 2007 Rockford and Catarina acquisitions. The remaining 2008 impairment came from proved properties in the Gulf of Mexico, the Greater Green River Basin in Wyoming, and the Company's Hanging Woman Basin coalbed methane project.

For the years ended December 31, 2010, 2009, and 2008, the Company recorded expense related to the abandonment and impairment of unproved properties of $2.0 million, $45.4 million, and $39.0 million, respectively. The largest specific components of the 2009 impairment related to the Floyd Shale acreage located in Mississippi and acreage in Oklahoma. The largest specific component of the 2008 impairment related to acreage within the Olmos shallow gas formation in South Texas.

Sales of Proved and Unproved Properties

The sale of a partial interest in a proved oil and gas property is accounted for as normal retirement, and no gain or loss is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. A gain or loss is recognized for all other sales of producing properties and is included in the accompanying consolidated statements of operations.

The sale of a partial interest in an unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to the ultimate recovery of the cost applicable to the interest retained. A gain on the sale is recognized to the extent that the sales price exceeds the carrying amount of the unproved property. A gain or loss is recognized for all other sales of nonproducing properties and is included in the accompanying consolidated statements of operations. For additional discussion, please refer to Note 3—Divestitures and Assets Held for Sale.

Materials Inventory

The Company's materials inventory is primarily comprised of tubular goods to be used in future drilling operations. Materials inventory is valued at the lower of cost or market and totaled $22.5 million and $24.5 million at December 31, 2010, and 2009, respectively. There were no materials inventory write downs for the years ended December 31, 2010, and 2008. The Company incurred net materials inventory write-downs for year the ended December 31, 2009, of $14.2 million as a result of the decrease in value of tubular goods.

Assets Held for Sale

Any properties held for sale as of the date of presentation of the balance sheet have been classified as assets held for sale and are separately presented on the accompanying consolidated balance sheets at the lower of net book value or fair value less the cost to sell. The asset retirement obligation liabilities related to such properties have been reclassified to asset retirement obligations associated with oil and gas properties held for sale in the consolidated balance sheets. For additional discussion on assets held for sale, please refer to Note 3—Divestitures and Assets Held for Sale.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets which range from three to thirty years. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Intangible Assets

As of December 31, 2010, and 2009, the Company's other noncurrent assets in the accompanying consolidated balance sheets include $4.4 million and $380,000, respectively, of intangible assets. These assets arise from acquired oil and gas sale contracts with favorable pricing terms and acquired indefinite life water rights. They do not qualify as derivatives or hedges. All indefinite life intangible assets are evaluated for impairment at least annually and if such indicators arise.

Cash Settlement Balancing

The Company uses the sales method of accounting for gas revenue whereby sales revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. An asset or liability is recognized to the extent that there is an imbalance in excess of the remaining gas reserves on the underlying properties.

The Company's gas imbalance position at December 31, 2010, and 2009, resulted in the recording of $1.5 million and $1.8 million, respectively, to accounts receivable and $934,000 and $1.2 million, respectively, to accounts payable and accrued expenses.

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Derivative Financial Instruments

The Company seeks to manage or reduce commodity price risk on production by hedging cash flows. The Company intends for derivative instruments used for this purpose to qualify as and to be designated as cash flow hedges. The Company seeks to minimize its basis risk and indexes its oil hedges to NYMEX prices, its NGL hedges to Oil Price Information Service ("OPIS") prices, and the majority of its gas hedges to various regional index prices associated with pipelines in proximity to the Company's areas of gas production. For additional discussion on derivatives, please see Note 10—Derivative Financial Instruments.

Net Profits Plan

The Company records the estimated fair value of future payments under the Net Profits Plan as a noncurrent liability in the accompanying consolidated balance sheets. The estimated liability is a discounted calculation and has underlying assumptions including estimates of oil and gas reserves, recurring and workover lease operating expense, production and ad valorem tax rates, present value discount factors, and pricing assumptions. The estimates the Company uses in calculating the long-term liability are adjusted from period-to-period based on the most current information attributable to the underlying assumptions. Changes in the estimated liability of future payments associated with the Net Profits Plan are recorded as increases or decreases to expense in the current period as a separate line item in the accompanying consolidated statements of operations as these changes are considered changes in estimates.

The distribution amounts due to participants and payable in each period under the Net Profits Plan as cash compensation related to periodic operations are recognized as compensation expense and are included within general and administrative expense and exploration expense in the accompanying consolidated statements of operations. The corresponding current liability is included in accounts payable and accrued expenses in the accompanying consolidated balance sheets. This treatment provides for a consistent matching of cash expense with net cash flows from the oil and gas properties in each respective pool of the Net Profits Plan. For additional discussion, please refer to the heading *Net Profits Plan* in Note 7—Compensation Plans and Note 11—Fair Value Measurements.

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. For additional discussion, please refer to Note 9—Asset Retirement Obligations.

Revenue Recognition

The Company derives revenue primarily from the sale of produced natural gas and crude oil. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported as separate expenses and are included in oil and gas production expense in the accompanying consolidated statements of operations. Revenue is recorded in the month the Company's production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of its properties, their historical performance, NYMEX and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates.

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Major Customers

During 2010, the Company had one customer individually account for 11 percent of our total oil and gas production revenue. During 2009, the Company had one customer that individually accounted for 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.

Stock Based Compensation

At December 31, 2010, the Company had stock-based employee compensation plans that included RSUs, PSAs, stock awards, and stock options issued to employees and non-employee directors as more fully described in Note 7—Compensation Plans. The Company records expense associated with the fair value of stock-based compensation in accordance with authoritative guidance. The Company records compensation expense associated with the issuance of RSUs and PSAs based on the estimated fair value of these awards determined at the time of grant.

Income Taxes

The Company accounts for deferred income taxes whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amount on the financial statements and the tax basis of assets and liabilities, as measured using current enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recorded or settled, respectively. The Company records deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis.

Earnings per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the weighted-average basic common shares outstanding for the respective period. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income or loss per common share of stock is calculated by dividing adjusted net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of unvested RSUs, in-the-money outstanding options to purchase the Company's common stock, contingent PSAs, and shares into which the 3.50% Senior Convertible Notes are convertible.

The Company's 3.50% Senior Convertible Notes have a net-share settlement right whereby each $1,000 principal amount of notes may be surrendered for conversion to cash in an amount equal to the principal amount and, if applicable, shares of common stock or cash or any combination of common stock and cash for the amount of conversion value in excess of the principal amount. The treasury stock method is used to measure the potentially dilutive impact of shares associated with this conversion feature. The 3.50% Senior Convertible Notes have not been dilutive for any reporting period that they have been outstanding and therefore do not impact the diluted earnings per share calculation for the years ended December 31, 2010, 2009, and 2008.

The PSAs represent the right to receive, upon settlement of the PSAs after the completion of the three-year performance period, a number of shares of the Company's common stock that may range from zero to two times the number of PSAs granted on the award date. The number of potentially dilutive shares related to PSAs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For additional discussion on PSAs, please refer to Note 7—Compensation Plans under the heading *Performance Share Awards Under the Equity Incentive Compensation Plan.*

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, 3.50% Senior Convertible Notes, and PSAs. When there is a loss from continuing operations, all potentially dilutive shares will be anti-dilutive. There were no dilutive shares for the year ended December 31, 2009, because the Company recorded a loss for

the year. Unvested RSUs, contingent PSAs, and in-the-money options had a dilutive impact for the years ended December 31, 2010, and 2008, as calculated in the basic and diluted earnings per share table below.

The following table details the weighted-average dilutive and anti-dilutive securities related to stock options, RSUs, and PSAs for the years presented:

	For the Years Ended December 31, 2010	2009	2008
Dilutive	1,720,149	—	890,189
Anti-dilutive	—	1,152,127	330,231

The following table sets forth the calculations of basic and diluted earnings per share:

	For the Years Ended December 31, 2010	2009	2008
	(in thousands, except per share amounts)		
Net income (loss)	$ 196,837	$ (99,370)	$ 87,348
Basic weighted-average common shares outstanding	62,969	62,457	62,243
Add: dilutive effect of stock options, unvested RSUs, and contingent PSAs	1,720	—	890
Add: dilutive effect of 3.50% Senior Convertible Notes	—	—	—
Diluted weighted-average common shares outstanding	64,689	62,457	63,133
Basic net income (loss) per common share	$ 3.13	$ (1.59)	$ 1.40
Diluted net income (loss) per common share	$ 3.04	$ (1.59)	$ 1.38

Comprehensive Income (Loss)

Comprehensive income or loss consists of net income or loss, the unrealized gain or loss for the effective portion of derivative instruments classified as cash flow hedges, and the minimum pension liability adjustment that was recognized as a component of net periodic benefit cost. Comprehensive income or loss is presented net of income taxes in the accompanying consolidated statements of stockholders' equity and comprehensive income (loss).

The changes in the balances of components comprising other comprehensive income and loss are presented in the following table:

	Derivative Instruments	Pension Liability Adjustments	Other Comprehensive Income (Loss)
		(in thousands)	
For the year ended December 31, 2008			
Before tax income (loss)	$ 358,632	$ (1,941)	$ 356,691
Tax benefit (expense)	(135,164)	734	(134,430)
After deferred tax income (loss)	$ 223,468	$ (1,207)	$ 222,261
For the year ended December 31, 2009			
Before tax income (loss)	$ (165,684)	$ 119	$ (165,565)
Tax benefit (expense)	62,363	(45)	62,318
After deferred tax income (loss)	$ (103,321)	$ 74	$ (103,247)
For the year ended December 31, 2010			
Before tax income (loss)	$ 37,512	$ (1,570)	$ 35,942
Tax benefit (expense)	(14,060)	590	(13,470)
After deferred tax income (loss)	$ 23,452	$ (980)	$ 22,472

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Company's credit facility approximates its fair value as it bears interest at a floating rate that approximates a current market rate. The Company had $48.0 million and $188.0 million in loans outstanding under its revolving credit agreement as of December 31, 2010, and 2009, respectively. The Company's 3.50% Senior Convertible Notes are recorded at cost, and the fair value is disclosed in Note 5—Long-Term Debt. The Company has derivative financial instruments that are recorded at fair value and changes in fair value are recorded to accumulated other comprehensive loss in the accompanying consolidated balance sheets to the extent they are effective. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Industry Segment and Geographic Information

The Company operates exclusively in the exploration and production segment and all of the Company's operations are conducted entirely in the United States in North America. The Company reports as a single industry segment. The Company's gas marketing function provides mostly internal services and acts as the first purchaser of natural gas and natural gas liquids produced by the Company in certain cases. We consider the Company's marketing function as ancillary to the Company's oil and gas producing activities. The amount of income these operations generate from marketing gas produced by third parties is not material to the Company's financial position, and segmentation of such activity would not provide a better understanding of the Company's performance. However, gross revenue and expense related to marketing activities for gas produced by third parties are presented discretely in the accompanying consolidated statements of operations.

Off-Balance Sheet Arrangements

As part of its ongoing business, the Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. The Company has not been involved in any unconsolidated SPE transactions.

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The Company evaluates its transactions to determine if any variable interest entities exist. If it is determined that SM Energy is the primary beneficiary of a variable interest entity, that entity is consolidated into SM Energy.

Recently Issued Accounting Standards

The Company partially adopted new fair value measurement authoritative guidance that requires additional disclosures surrounding transfers between Levels 1 and 2, inputs and valuation techniques used to value Level 2 and 3 measurements, and push down of previously prescribed fair value disclosures to each class of asset and liability for Levels 1, 2, and 3. These disclosures were effective for the Company for the quarter ended March 31, 2010. The partial adoption did not have a material impact on the Company's consolidated financial statements. Please refer to Note 11—Fair Value Measurements for additional information on the recent adoption of new authoritative accounting guidance.

The Company will apply new fair value measurement authoritative guidance requiring that purchases, sales, issuances, and settlements for Level 3 measurements be disclosed. These disclosures are effective for interim and annual reporting periods beginning after December 15, 2010. The Company will apply this new guidance in the Company's Quarterly Report on Form 10-Q for the period ended March 31, 2011. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

Note 2—Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	As of December 31,	
	2010	2009
	(in thousands)	
Accrued oil and gas sales	$ 108,393	$ 80,085
Due from joint interest owners	50,018	29,719
State severance tax refunds	2,114	4,638
Other	2,665	1,694
Total accounts receivable	$ 163,190	$ 116,136

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Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2010	2009
	(in thousands)	
Accrued drilling costs	$ 235,975	$ 100,960
Revenue and severance tax payable	37,066	33,370
Accrued lease operating expense	17,643	13,760
Accrued property taxes	5,979	4,747
Joint owner advances	24,698	5,312
Accrued compensation	45,235	23,607
Trade payables	11,323	11,633
Plug and abandonment liability	11,679	23,665
Accrued marketed gas system expense	3,822	8,313
Settled hedge payable	6,371	1,637
Other	17,863	9,238
Total accounts payable and accrued expenses	$ 417,654	$ 236,242

Note 3—Divestitures and Assets Held for Sale

Permian Divestiture

In December 2010 the Company completed the divestiture of certain non-strategic oil properties located in our Permian region that were classified as held for sale at September 30, 2010. Total cash received, before commission 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 is approximately $19.9 million and may be impacted by the forthcoming post-closing adjustments mentioned above. The Company determined that the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Legacy Divestiture

In February 2010 the Company completed the divestiture of certain non-strategic oil properties located in Wyoming to Legacy Reserves Operating LP, a wholly-owned subsidiary of Legacy Reserves LP ("Legacy"). Total cash received, before commission costs and Net Profits Plan payments, was $125.3 million, of which $6.5 million was received as a deposit in December 2009. The final gain on sale related to the divestiture is approximately $66.7 million. These properties were classified as held for sale at December 31, 2009. The Company determined that the sale did not qualify for discontinued operations accounting. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code").

Sequel Divestiture

In March 2010 the Company completed the divestiture of certain non-strategic oil properties located in North Dakota to Sequel Energy Partners, LP, Bakken Energy Partners, LLC, and Three Forks Energy Partners, LLC (collectively referred to as "Sequel"). Total cash received, before commission costs and Net Profits Plan payments, was $129.1 million. The final gain on sale related to the divestiture is approximately $53.1 million. These properties were classified as held for sale at December 31, 2009. The Company determined that the sale did not qualify for discontinued operations accounting. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code.

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Hanging Woman Basin Divestiture

In December 2009 the Company completed the divestiture of certain non-strategic coalbed methane properties located in the Hanging Woman Basin in our Rocky Mountain region. Total cash received, before commission costs and Net Profits Plan payments, was $23.3 million. The final gain on sale related to the divestiture was approximately $12.9 million. The Company determined that the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Abraxas Divestiture

In January 2008 the Company completed the divestiture of certain non-strategic oil and gas properties as the second step of a reverse 1031 exchange. The sold properties were located primarily in our Rocky Mountain and Mid-Continent regions, and were sold to Abraxas Petroleum Corporation and Abraxas Operating, LLC. The final sales price, net of commission costs, was $129.4 million. The final gain on sale related to the divestiture was approximately $53.4 million, net of commission costs and Net Profit Plan payments. The Company determined that the sale did not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted and a measurement for impairment is performed to expense any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale for assets for which fair value is determined to be less than the carrying value of the assets.

As of December 31, 2010, the accompanying consolidated balance sheets include $86.8 million in book value of assets held for sale, net of accumulated depletion, depreciation, and amortization. The corresponding asset retirement obligation liability of $2.1 million is also separately presented. The above assets held for sale and asset retirement obligation liability amounts include certain non-core properties located in Pennsylvania, and the Rocky Mountain and Mid-Continent regions. The Company began marketing these assets in the third quarter of 2010. The Company determined that these planned asset sales do not qualify for discontinued operations accounting under financial statement presentation authoritative guidance.

Subsequent to year end, the Company divested of the Rocky Mountain region properties that were classified as assets held for sale at December 31, 2010. The cash received at closing was $44.4 million before commission costs and Net Profit Plan payments. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during the first half of 2011.

Additionally subsequent to year end, the Company plans to divest of a portion of the Company's oil and gas assets located in our South Texas & Gulf Coast region. The net book value of these assets, net of accumulated depletion, depreciation, and amortization, is approximately $29 million. These assets were not classified as held for sale as of December 31, 2010.

Note 4—Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
Current income tax expense (benefit)			
Federal	$ 2,903	$ (21,926)	$ 17,863
State	639	1,567	1,361
Deferred income tax expense (benefit)	114,517	(39,735)	38,164
Total income tax expense (benefit)	$ 118,059	$ (60,094)	$ 57,388
Effective tax rates	37.5%	37.7%	39.7%

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As a result of the exercise of stock options, the Company reduced its income tax payable in 2010 and 2008. The excess income tax benefit to the Company associated with stock awards was $854,000 and $13.9 million in 2010 and 2008, respectively. There was no excess income tax benefit associated with stock awards in 2009.

The components of the net deferred income tax liabilities are as follows:

December 31,

	2010	2009
	(in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$ 528,652	$ 419,585
Interest on Senior Convertible Notes	2,219	1,937
Other	2,723	1,378
Total deferred tax liabilities	533,594	422,900
Deferred tax assets:		
Net Profits Plan liability	50,922	63,902
Stock compensation	13,143	9,647
State tax net operating loss carryforward or carryback	10,772	10,915
Unrealized derivative liability	6,929	21,107
Other long-term liabilities	19,740	17,277
Total deferred tax assets	101,506	122,848
Valuation allowance	(2,164)	(3,203)
Net deferred tax assets	99,342	119,645
Total net deferred tax liabilities	434,252	303,255
Less: current deferred income tax liabilities	(2,710)	(1,366)
Add: current deferred income tax assets	11,593	6,300
Non-current net deferred tax liabilities	$ 443,135	$ 308,189
Current federal income tax refundable	$ 8,482	$ 32,773
Current state income tax payable	$ 294	$ 168

At December 31, 2010, the Company had estimated state net operating loss carryforwards of approximately $259 million expiring between 2011 and 2030. The Company has other state tax credits of $349,000 which expire between 2011 and 2020. The majority of the Company's valuation allowance relates to state net operating loss carryforwards, state tax credits, and state and federal income tax benefit amounts which the Company anticipates will expire before they can be utilized. Permanent items included in the calculation of income tax for certain states are anticipated to impact the Company's ability to deduct operating losses and realize federal income tax deduction benefits in certain states and the Company adjusts its valuation allowances accordingly. The change in the valuation allowance from 2009 to 2010 indicated below reflects a change in the Company's position regarding anticipated utilization of state net operating losses as a result of actual net income or loss occurring subsequent to a 2007 change in the Company's operating structure and a review of expectations of contingent future performance.

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Federal income tax expense differs from the amount that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes primarily due to the effect of state income taxes, percentage depletion, the estimated effect of the domestic production activities deduction, 2008 impairment of goodwill, changes in valuation allowances, and other permanent differences, as follows:

	For the Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
Federal statutory tax (benefit)	$ 110,214	$ (55,812)	$ 50,526
Increase (decrease) in tax resulting from State tax (benefit) (net of federal benefit)	7,750	(5,141)	4,669
Change in valuation allowance	(1,039)	56	(409)
Statutory depletion	(266)	(189)	(294)
Domestic production activities deduction	—	—	(275)
Goodwill	—	—	3,308
Other	1,400	992	(137)
Income tax expense (benefit)	$ 118,059	$ (60,094)	$ 57,388

Acquisitions, divestitures, drilling activity, and basis differentials impacting the prices received for crude oil and natural gas affect apportionment of taxable income to the states where the Company owns oil and gas properties. As its apportionment factors change, the Company's blended state income tax rate changes. This change, when applied to the Company's total temporary differences, impacts the total income tax reported in the current year and is reflected in state taxes in the table above. Items affecting state apportionment factors are evaluated after completion of the prior year income tax return and when significant acquisitions or divestitures are closed during the current year.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before 2007. During the first quarter of 2010, the Internal Revenue Service initiated an audit of SM Energy for the 2006 tax year as a result of a net operating loss carryback from the Company's 2008 tax year. The audit was focused primarily on compensation related issues. The audit was successfully concluded in the second quarter of 2010 with no changes to Company reported amounts. No amended Federal or state returns were required. The Joint Committee on Taxation has approved a $5.5 million refund, which is included in refundable income taxes on the accompanying balance sheets at December 31, 2010 and was received subsequent to year end. On July 20, 2010, the Company received $22.9 million related to an initial claim for net operating loss carry back from its 2009 tax year to its 2005 tax year. The Company's remaining refundable income tax balance at December 31, 2010, reflects an additional net operating loss carry-back from filing a revised income tax return for the 2009 tax year prior to the extended return due date and an expected refund of tax paid in 2009. In the fourth quarter of 2010, the Internal Revenue Service began a full audit of the Company's 2009 tax year. That audit was still in progress at December 31, 2010.

The Internal Revenue Service initiated an audit of the Company's 2005 tax year in 2008 and concluded the audit in the first quarter of 2009 with a refund to the Company of $278,000 plus interest of $41,000. Related amended state income tax returns were filed in the second quarter of 2009. There was no change to the provision for income tax expense as a result of the examination. In the fourth quarter of 2009 the Company received a refund of $5.0 million related to its 2008 income tax return.

At December 31, 2008, the Company recognized an impairment of goodwill recorded as part of the Agate Petroleum, Inc. acquisition in 2005. The tax benefit is not calculated upon the recognition of this expense. This item resulted in a 2.2 percent increase in the Company's effective tax rate for the year ended December 31, 2008.

The Company complies with uncertainty provisions of the income tax authoritative accounting guidance. The entire amount of unrecognized tax benefit would affect the Company's effective tax rate if recognized. Interest expense in the 2010 accompanying consolidated statements of operations includes $42,000 associated with income tax. Penalties associated with income tax are recorded in general and administrative expense in the accompanying consolidated statements of operations. There were no penalties associated with income tax recorded for the years ended December 31, 2010, 2009, and 2008.

The total amount recorded for unrecognized tax benefits is presented below:

	For the Years Ended December 31,		
	2010	2009	2008
	(in thousands)		
Beginning balance	$ 884	$ 994	$ 957
Additions for tax positions of prior years	244	231	173
Reductions for lapse of statute of limitations	(321)	(341)	(136)
Ending balance	$ 807	$ 884	$ 994

Note 5—Long-term Debt

Revolving Credit Facility

The Company executed a Third Amended and Restated Credit Agreement on April 14, 2009. This amended revolving credit facility replaced the previous facility. The Company incurred $11.1 million of deferred financing costs in association with the amended credit facility. Borrowings under the facility are secured by a pledge, in favor of the lenders, of collateral that includes the majority of the Company’s oil and gas properties.   The credit facility has a maturity date of July 31, 2012. The borrowing base under the credit facility is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of SM Energy’s oil and gas properties and other assets, as determined by the bank syndicate. In September 2010, the lending group redetermined our reserve-backed borrowing base under the credit facility at an amount of $1.1 billion, which was decreased to $1.0 billion subsequent to year end due to the issuance of the 6.625% Senior Notes as discussed below. The Company has an aggregate commitment amount of $678 million under the credit facility. The Company must comply with certain covenants under the terms of its credit facility agreement, including the limitation of the Company’s annual dividend rate to no more than $0.25 per share. The Company is in compliance with all covenants under the credit facility as of December 31, 2010, and through the date of this filing. Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate (“LIBOR”) plus the applicable margin from the utilization table, and Alternative Base Rate (“ABR”) and swingline loans accrue interest at Prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying consolidated statements of operations.

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%	³25% <50%	³50% <75%	³75%
Eurodollar Loans	2.000%	2.250%	2.500%	2.750%
ABR Loans or Swingline Loans	1.000%	1.250%	1.500%	1.750%
Commitment Fee Rate	0.500%	0.500%	0.500%	0.500%

The Company had $48.0 million and $188.0 million in outstanding loans under its revolving credit agreement on December 31, 2010, and 2009, respectively. There were no outstanding borrowings under the Company’s credit facility as of February 18, 2011. The Company had $677.5 million, $629.5 million, and $489.4 million of available borrowing capacity under this facility as of February 18, 2011, December 31, 2010, and 2009, respectively. The Company had a single letter of credit outstanding in the amount of $483,000 at February 18, 2011, and December 31, 2010, and $569,000 as of December 31, 2009. This letter of credit reduced the amount available under the commitment amount on a dollar-for-dollar basis.

3.50% Senior Convertible Notes Due 2027

On April 4, 2007, the Company issued $287.5 million in aggregate principal amount of 3.50% Senior Convertible Notes. The 3.50% Senior Convertible Notes mature on April 1, 2027, unless converted prior to maturity, redeemed, or

purchased by the Company. The 3.50% Senior Convertible Notes are unsecured senior obligations and rank equal in right of payment with all of the Company’s existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt.

Holders may convert their notes based on a conversion rate of 18.3757 shares of the Company’s common stock per $1,000 principal amount of the 3.50% Senior Convertible Notes (which is equal to an initial conversion price of approximately $54.42 per share), subject to adjustment and contingent upon and only under the following circumstances: (1) if the closing price of the Company’s common stock reaches specified thresholds or the trading price of the notes falls below specified thresholds, (2) if the notes are called for redemption, (3) if specified distributions to holders of the Company’s common stock are made or specified corporate transactions occur, (4) if a fundamental change occurs, or (5) during the ten trading days prior to but excluding the maturity date. As of December 31, 2009, the notes and underlying shares had been registered under a shelf registration statement. In 2010 the Company deregistered the shelf registration statement for the 3.50% Senior Convertible Notes. If the Company becomes involved in a material transaction or corporate development, it may suspend trading of the 3.50% Senior Convertible Notes under the prospectus. In the event the suspension period exceeds 45 days within any three-month period or 90 days within any twelve-month period, the Company will be required to pay additional interest to all holders of the 3.50% Senior Convertible Notes, not to exceed a rate per annum of 0.50 percent of the issue price of the 3.50% Senior Convertible Notes; provided that no such additional interest shall accrue after April 4, 2009.

Upon conversion of the 3.50% Senior Convertible Notes, holders will receive cash or common stock or any combination thereof as elected by the Company. At any time prior to the maturity date of the notes, the Company has the option to unilaterally and irrevocably elect to net share settle its obligations upon conversion of the notes in cash and, if applicable, shares of common stock. If the Company makes this election, then the Company will pay the following to holders for each $1,000 principal amount of notes converted in lieu of shares of common stock: (1) an amount in cash equal to the lesser of (i) $1,000 or (ii) the conversion value determined in the manner set forth in the indenture for the 3.50% Senior Convertible Notes, and (2) if the conversion value exceeds $1,000, the Company will also deliver, at its election, cash or common stock or a combination of cash and common stock with respect to the remaining value deliverable upon conversion. Currently, it is the Company’s intention to net share settle the 3.50% Senior Convertible Notes. However, the Company has not made this a formal legal irrevocable election and thereby reserves the right to settle the 3.50% Senior Convertible Notes in any manner allowed under the indenture as business conditions warrant.

If the holder elects to convert its notes in connection with certain events that constitute a change of control before April 1, 2012, the Company will pay, to the extent described in the related indenture, a make-whole premium by increasing the conversion rate applicable to the 3.50% Senior Convertible Notes. In addition, the Company will pay contingent interest in cash, commencing with any six-month period beginning on or after April 1, 2012, if the average trading price of a note for the five trading days ending on the third trading day immediately preceding the first day of the relevant six-month period equals 120 percent or more of the principal amount of the 3.50% Senior Convertible Notes.

On or after April 6, 2012, the Company may redeem for cash all or a portion of the 3.50% Senior Convertible Notes at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any, up to but excluding the applicable redemption date. Holders of the 3.50% Senior Convertible Notes may require the Company to purchase all or a portion of their notes on each of April 1, 2012, April 1, 2017, and April 1, 2022, at a purchase price equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any, up to but excluding the applicable purchase date. On April 1, 2012, the Company may pay the purchase price in cash, in shares of common stock, or in any combination of cash and common stock. On April 1, 2017, and April 1, 2022, the Company must pay the purchase price in cash.

Capitalized Interest

Capitalized interest costs for the Company for the years ended December 31, 2010, 2009, and 2008, were $4.3 million, $1.9 million, and $4.7 million, respectively.

6.625% Senior Notes Due 2019

On February 7, 2011, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. The 6.625% Senior Notes mature on February 15, 2019. The Company received net proceeds of approximately $342.1 million after deducting discounts and fees. The net proceeds will be used to repay borrowings under the Company's revolving credit facility and to fund the Company's ongoing capital expenditure program.

The 6.625% Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 6.625% Senior Notes. 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.

Additionally, on February 7, 2011, the Company entered into a registration rights agreement that provides holders of the 6.625% Senior Notes certain rights relating to registration of the 6.625% Senior Notes under the Securities Act of 1933, as amended (the "Securities Act"). Pursuant to the registration rights agreement, the Company will file an exchange offer registration statement with the SEC with respect to an offer to exchange the 6.625% Senior Notes for substantially identical notes that are registered under the Securities Act. Under certain circumstances, in lieu of a registered exchange offer, the Company has agreed to file a shelf registration statement with respect to the 6.625% Senior Notes. If the exchange offer is not completed on or before February 7, 2012, or the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, then the Company agrees to pay additional interest with respect to the 6.625% Senior Notes in an amount not to exceed one percent of the principal amount of the 6.625% Senior Notes until the exchange offer is completed or the shelf registration statement is declared effective.

Note 6 — Commitments and Contingencies

The Company has entered into various agreements, which include drilling rig leasing contracts, of approximately $142.3 million, gas gathering through-put commitments of $181.1 million, office space leases including maintenance of approximately $33.2 million, hydraulic fracturing contracts of $42.7 million, and other miscellaneous contracts and leases of $9.0 million. The annual minimum payments for the next five years and thereafter are presented below:

Years Ending December 31,	(in thousands)
2011	$ 106,725
2012	61,956
2013	54,472
2014	44,046
2015	21,417
Thereafter	119,721
Total	$ 408,337

Subsequent to year end the Company entered into a hydraulic fracturing services contract. The total commitment is $180.0 million over a two year term provided however, our liability upon early termination of this contract may not exceed $24 million. The commitment amount is not reflected in the amounts above.

The Company leases office space under various operating leases with terms extending as far as May 31, 2022. Rent expense for 2010 was $2.7 million. Rent expense, net of sub lease rent of $185,000 per year, for 2009 and 2008 was $2.3 million, and $2.4, respectively. The Company also leases office equipment under various operating leases.

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such pending litigation and claims will not have a material effect on the results of operations, the financial position, or cash flows of the Company.

The Company is currently engaged in litigation regarding an overriding royalty interest in less than one percent of the Company's net acreage in the Eagle Ford shale play in South Texas. The Company believes that the lawsuit is without merit and will continue to contest the litigation. However, the Company is not able to accurately predict the final outcome of the lawsuit, and if the plaintiffs were to prevail the overriding royalty interest would reduce the Company's net revenue interest in the affected acreage. The Company does not believe that an unfavorable outcome is probable, nor that if the plaintiffs prevail there would be a material adverse effect on the financial position of the Company. As a result of the current facts and circumstances of the case, no accrual has been made for such loss.

Note 7 — Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan based on a performance measurement framework whereby selected eligible employee participants may be awarded an annual cash bonus. The plan document provides that no participant may receive an annual bonus under the plan of more than 200 percent of his or her base salary. As the plan is currently administered, any awards under the plan are based on Company and regional performance, and are then further refined by individual performance. The Company accrues cash bonus expense based upon the Company's current year's performance. Included in general and administrative and exploration expense in the accompanying consolidated statements of operations are $21.6 million, $7.8 million, and $6.4 million of cash bonus expense related to the specific performance year for the years ended December 31, 2010, 2009, and 2008, respectively.

Equity Incentive Compensation Plan

There are several components to the equity compensation plan that are described in this section. Various types of equity awards have been granted by the Company in different periods.

In May 2006 the stockholders approved the 2006 Equity Incentive Compensation Plan, which was subsequently renamed the Equity Incentive Compensation Plan (the "Equity Plan") Plan to authorize the issuance of restricted stock, RSUs, 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 St. Mary Land & Exploration Company Stock Option Plan, the St. Mary Land & Exploration Company Incentive Stock Option Plan, the St. Mary Land & Exploration Company Restricted Stock Plan, and the St. Mary Land & Exploration Company Non-Employee Director Stock Compensation Plan (collectively referred to as the "Predecessor Plans"). All grants of equity are now made pursuant to the Equity Plan, and no further grants will be made under the Predecessor Plans. Each outstanding award under the Predecessor Plans 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. An amendment and restatement of the Equity Plan was approved by the Company's stockholders at the 2008 annual stockholders' meeting held on May 21, 2008. The Equity Plan was further amended at the 2009 annual stockholders' meeting held on May 20, 2009, and again on July 30, 2010, primarily to reflect the change in the name of the Company from St. Mary Land & Exploration Company to SM Energy Company.

As of December 31, 2010, 2.6 million shares of common stock remained available for grant under the Equity Plan. The issuance of a direct share benefit such as an outright grant of common stock, a grant of a restricted share, a RSU grant, or a PSA grant, counts as 1.43 shares against the number of shares available to be granted under the Equity Plan. At the end of a three-year performance period a final multiplier ranging between zero and two is applied to each PSA so that each performance share granted has the potential to result in the issuance of two shares of common stock. Consequently, each performance share granted may count as 2.86 shares against the number of shares available to be granted under the Equity Plan. Stock option grants count as one share for each instrument granted against the number of shares available to be granted under the Equity Plan. The Company has outstanding stock option awards under the Predecessor Plans.

Performance Share Awards Under the Equity Incentive Compensation Plan

PSAs are the primary form of long-term equity incentive compensation for the Company. The PSA factor is based on the Company's performance after completion of a three-year performance period. The performance criteria for

the PSAs are based on a combination of the Company's annualized TSR for the performance period and the relative measure of the Company's TSR compared with the annualized TSR of an index comprised of certain peer companies for the performance period. PSAs are recognized as general and administrative and exploration expense over the vesting period of the award.

The Company granted 387,651 PSAs on July 1, 2010, 725,092 PSAs on August 1, 2009, and 465,751 PSAs on August 1, 2008. The fair value of these grants was $20.3 million, $25.8 million, and $12.3 million for the July 1, 2010, August 1, 2009, and August 1, 2008 grants, respectively. The PSAs vest 1/7th, 2/7(ths), and 4/7(ths) on the first three anniversary dates of their issuances.

In measuring compensation expense related to the grant of PSAs, the Company estimates the fair value of the award on the grant date. The fair value of PSAs is measured by a stochastic process method using the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSAs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the three-year performance period. By using a stochastic simulation the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences to the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSAs.

A summary of the status and activity of PSAs for the years ending December 31, 2010, 2009, and 2008 is presented in the following table:

	2010		2009		2008	
	PSAs	Weighted-Average Grant-Date Fair Value	PSAs	Weighted-Average Grant-Date Fair Value	PSAs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	1,069,090	$ 32.52	464,333	$ 26.48	—	$ —
Granted	387,651	$ 52.35	725,092	$ 35.59	465,751	$ 26.48
Vested(1)	(210,801)	$ 31.18	(76,781)	$ 27.20	—	$ —
Forfeited	(135,274)	$ 34.28	(43,554)	$ 28.62	(1,418)	$ 26.48
Non-vested at end of year	1,110,666	$ 39.48	1,069,090	$ 32.52	464,333	$ 26.48

(1) The number of awards vested assume a one multiplier. The final number of shares issued may vary depending on the ending three-year multiplier, which ranges from zero to two.

The total fair value of PSAs that vested during the years ended December 31, 2010, and 2009 was $6.6 million and $1.8 million, respectively. Total expense recorded for PSAs was $17.7 million, $9.3 million, and $2.5 million for the years ended December 31, 2010, 2009, and 2008, respectively. As of December 31, 2010, there was $22.6 million of total unrecognized expense related to PSAs, which is being amortized through 2013.

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

The Company grants restricted stock or RSUs as part of the long-term incentive program to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards are determined by the Board of Directors and are set forth in the award agreements. Each RSU represents a right for one share of the Company's common stock to be delivered upon settlement of the award at the end of a specified period. These grants are determined annually based on the results of the PSA awards. RSUs are recognized as general and administrative and exploration expense over the vesting period of the award.

The Company issued 126,821 RSUs on July 1, 2010, and 241,745 RSUs on August 1, 2009. The fair value associated with these issuances was $5.1 million and $5.8 million, respectively. These RSUs vest 1/7th, 2/7(ths), and 4/7(ths) on the first three anniversary dates of their issuances.

SM Energy issued 265,373 RSUs on June 30, 2008, as a transitional award to employees when the Company moved from the standalone RSU equity incentive compensation plan to the PSA program. The total fair value associated with this issuance was $17.2 million as measured on the grant date. The granted RSUs vest one third on each date of December 15th 2008, 2009, and 2010.

The Company issued 158,744 RSUs on February 28, 2008, with a fair value of $6.0 million. These RSUs vested 25 percent immediately upon grant and 25 percent on each of the first three anniversary dates of the grant.

The Company issued an additional 2,044 and 4,290 RSUs to certain employees during 2010 and 2008, respectively. There were no additional RSUs issued in 2009. The total fair value associated with the 2010 and 2008 issuances was $100,000 and $164,000, respectively, as measured on the respective grant dates. These grants have various vesting schedules.

As of December 31, 2010, a total of 333,359 RSUs were outstanding, of which none were vested. The total expense associated with RSUs for the years ended December 31, 2010, 2009, and 2008, was $7.7 million, $7.9 million, and $11.0 million, respectively. As of December 31, 2010, there was $6.6 million of total unrecognized expense related to unvested RSU awards and is being amortized through 2013.

During 2010, 2009, and 2008, the Company settled 160,381, 215,700, and 678,197 RSUs, respectively. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued net shares of common stock of 113,103, 156,252, and 482,602 for 2010, 2009, and 2008, respectively. The remaining 47,278, 59,448, and 195,595 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs for 2010, 2009, and 2008, respectively.

Stock Awards Under the Equity Incentive Compensation Plan

As part of hiring a new senior executive in the second quarter of 2006, the Company granted a special common stock award of 20,000 shares that vested immediately upon commencement of employment. The fair value associated with this award was $727,600. In addition to this award, the employee was eligible to earn an additional 5,000 shares over a four-year period and an additional 15,000 shares contingent on the Company meeting certain net asset growth performance conditions over a four-year period. In 2010, 2009, and 2008, the Company issued 1,250, 1,250, and 3,750 shares with fair values of $43,000, $45,000, and $142,000, respectively related to these service-based and performance-based awards. The fair value of these awards is being recorded as compensation expense over the vesting period.

As part of hiring a new senior executive in the third quarter of 2008, the Company granted a special restricted stock award of 15,496 shares that vested one half on December 15, 2009, and the other half on December 15, 2010. The fair value of this award was $600,005 and was recorded as compensation expense over the vesting period. For the years ended December 31, 2010, 2009, and 2008 the Company recorded expense of $126,000, $358,000, and $115,000, respectively, related to this award.

A summary of the status and activity of non-vested stock awards and RSUs for the years ending December 31, 2010, 2009, and 2008, is presented below:

	2010		2009		2008	
	Stock Awards and RSUs	Weighted-Average Grant-Date Fair Value	Stock Awards and RSUs	Weighted-Average Grant-Date Fair Value	Stock Awards and RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	407,123	$ 34.67	402,297	$ 48.24	289,385	$ 32.26
Granted	128,865	$ 40.31	241,745	$ 23.87	443,903	$ 53.81
Vested	(160,398)	$ 46.30	(211,092)	$ 46.26	(291,659)	$ 22.92
Forfeited	(42,231)	$ 35.43	(25,827)	$ 50.35	(39,332)	$ 37.82
Non-vested at end of year	333,359	$ 31.16	407,123	$ 34.67	402,297	$ 48.24

The total fair value of RSUs that vested during the years ended December 31, 2010, 2009, and 2008, was $7.4 million, $4.9 million, and $9.4 million, respectively.

Cash flows resulting from excess tax benefits are to be classified as part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for vested RSUs and exercised options in excess of the deferred tax asset attributable to stock compensation costs for such RSUs and options. The Company recorded $854,000 and $13.9 million of excess tax benefits for the years ended December 31, 2010, and 2008, respectively, as cash inflows from financing activities. The Company recorded no excess tax benefits for the year ended December 31, 2009. Cash received from exercises under all share-based payment arrangements for the years ended December 31, 2010, 2009, and 2008, was $4.8 million, $1.6 million, and $10.8 million, respectively.

Stock Option Grants Under the Equity Incentive Compensation Plan

The Company has previously granted stock options under the St. Mary Land & Exploration Company Stock Option Plan and the St. Mary Land & Exploration Company Incentive Stock Option Plan. The last issuance of stock options was December 31, 2004. Stock options to purchase shares of the Company's common stock had been granted to eligible employees and members of the Board of Directors. All options granted under the option plans have been granted at exercise prices equal to the respective closing market price of the Company's underlying common stock on the grant dates. All stock options granted under the option plans are exercisable for a period of up to ten years from the date of grant.

During the year ended December 31, 2008, the Company recognized general and administrative and exploration expense of $17,000 related to stock options that were outstanding and unvested. There was no expense associated with stock options or unvested stock options outstanding for the years ended December 31, 2010 and 2009.

A summary of activity associated with the Company's Stock Option Plans during the last three years is presented in the following table:

	Shares	Weighted - Average Exercise Price	Aggregate Intrinsic Value
For the year ended December 31, 2008			
Outstanding, start of year	2,385,500	$ 12.62	
Exercised	(868,372)	$ 12.47	
Forfeited	(7,418)	$ 13.39	
Outstanding, end of year	1,509,710	$ 12.69	$ 11,529,600
Vested at end of year	1,509,710	$ 12.69	$ 11,529,600
Exercisable, end of year	1,509,710	$ 12.69	$ 11,529,600
For the year ended December 31, 2009			
Outstanding, start of year	1,509,710	$ 12.69	
Exercised	(189,740)	$ 8.40	
Forfeited	(45,050)	$ 13.38	
Outstanding, end of year	1,274,920	$ 13.31	$ 26,684,106
Vested at end of year	1,274,920	$ 13.31	$ 26,684,106
Exercisable, end of year	1,274,920	$ 13.31	$ 26,684,106
For the year ended December 31, 2010			
Outstanding, start of year	1,274,920	$ 13.31	
Exercised	(346,377)	$ 13.77	
Forfeited	(7,778)	$ 16.66	
Outstanding, end of year	920,765	$ 13.11	$ 42,192,057
Vested at end of year	920,765	$ 13.11	$ 42,192,057
Exercisable, end of year	920,765	$ 13.11	$ 42,192,057

A summary of additional information related to options outstanding as of December 31, 2010, follows:

Range of Exercise Prices	Options Outstanding and Exercisable: Number Of Options Outstanding and Exercisable	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price
$ 7.97 — $ 10.60	94,456	0.9 years	$ 9.72
10.86 — 11.95	99,230	1.5 years	11.45
12.03 — 12.08	74,209	1.5 years	12.04
12.50 — 12.50	117,765	2.0 years	12.50
12.53 — 12.53	90,067	2.3 years	12.53
12.66 — 12.66	74,239	2.8 years	12.66
13.39 — 13.39	27,617	2.8 years	13.39
13.65 — 13.65	113,045	2.5 years	13.65
14.25 — 14.25	171,505	3.0 years	14.25
20.87 — 20.87	58,632	4.0 years	20.87
Total	920,765		

The fair value of options was measured at the date of grant using the Black-Scholes Merton option-pricing model.

Director Shares

In 2010, 2009, and 2008, the Company issued 24,258, 50,094, and 23,113 shares, respectively, of restricted common stock from treasury to its non-employee directors pursuant to the Company's Equity Plan. The Company recorded expense related to the issuances of shares to non-employee directors of $781,000, $688,000, and $1.0 million for the years ended December 31, 2010, 2009, and 2008, respectively.

Employee Stock Purchase Plan

Under the Company's Employee Stock Purchase Plan ("the ESPP"), eligible employees may purchase shares of the Company's common stock through payroll deductions of up to 15 percent of 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 are restricted for a six month period from the date issued. The ESPP is intended to qualify under Section 423 of the IRC. The Company has set aside 2,000,000 shares of its common stock to be available for issuance under the ESPP, of which 1,415,327 shares are available for issuance as of December 31, 2010. Shares issued under the ESPP totaled 52,948 in 2010, 86,308 in 2009, and 45,228 in 2008. Total proceeds to the Company for the issuance of these shares were $1.7 million in 2010, $1.5 million in 2009, and $1.1 million in 2008, respectively.

The fair value of ESPP shares are measured at the date of grant using the Black-Scholes option-pricing model. The fair value of ESPP shares issued during the periods reported were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,		
	2010	2009	2008
Risk free interest rate	0.2%	0.3%	1.2%
Dividend yield	0.3%	0.5%	0.2%
Volatility factor of the expected market price of the Company's common stock	46.3%	95.1%	81.5%
Expected life (in years)	0.5	0.5	0.5

The Company expensed $550,000, $848,000, and $307,000 for the years ended December 31, 2010, 2009, and 2008, respectively, based on the estimated fair value of grants.

401(k) Plan

The Company has a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 60 percent of their base salaries up to the contribution limits established under the IRC. The Company matches each employee's contribution up to six percent of the employee's base salary and may make additional contributions at its discretion. The Company's contributions to the 401(k) Plan were $2.5 million, $2.5 million, and $2.0 million for the years ended December 31, 2010, 2009, and 2008, respectively. No discretionary contributions were made by the Company to the 401(k) Plan for any of these years.

Net Profits Plan

Under the Company's Net Profits Plan, all oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Company's Compensation Committee of the Board of Directors and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. In December 2007 the Board discontinued the creation of new pools under the Net Profits Plan. Consequently, the 2007 Net Profits Plan pool was the last pool established by the Company. All pools are fully vested as of December 31, 2010.

Cash payments made under the Net Profits Plan that have been recorded as either general and administrative expense or exploration expense are detailed in the table below:

	For the Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
General and administrative expense	$ 19,798	$ 18,399	$ 29,713
Exploration expense	2,633	1,463	6,604
Total	$ 22,431	$ 19,862	$ 36,317

Additionally, the Company made cash payments under the Net Profits Plan of $26.1 million, $724,000, and $15.1 million for the years ended December 31, 2010, 2009, and 2008, respectively, as a result of sales proceeds from divestitures. The cash payments are accounted for as a reduction in the gain on divestiture activity in the accompanying consolidated statements of operations.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying consolidated statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific functional line items based on the current allocation of actual distributions made by the Company. As time progresses, less of the distributions relate to prospective exploration efforts as more of the distributions are made to employees that have terminated employment and do not provide ongoing exploration support to the Company.

	For the Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
General and administrative benefit	$ 30,399	$ 6,572	$ 29,672
Exploration benefit	4,042	503	4,368
Total	$ 34,441	$ 7,075	$ 34,040

Note 8 — Pension Benefits

Pension Plans

The Company has a non-contributory defined benefit pension plan covering substantially all employees who meet age and service requirements (the "Qualified Pension Plan"). The Company also has a supplemental non-contributory pension plan covering certain management employees (the "Nonqualified Pension Plan").

The Company recognizes the funded status (i.e., the difference between the fair value of plan assets and the projected benefit obligation) of the Company's pension plan in the accompanying consolidated balance sheets as either an asset or a liability and recognizes a corresponding adjustment to accumulated other comprehensive income, net of tax. The projected benefit obligation is the actuarial present value of the benefits earned to date by plan participants based on employee service and compensation including the effect of assumed future salary increases. The accumulated benefit obligation uses the same factors as the projected benefit obligation but excludes the effects of assumed future salary increases. The Company's measurement date for plan assets and obligations is December 31.

Obligations and Funded Status for Both Pension Plans

	For the Years Ended December 31,	
	2010	2009
	(in thousands)	
Change in benefit obligations		
Projected benefit obligation at beginning of year	$ 18,550	$ 14,786
Service cost	3,392	2,500
Interest cost	1,120	934
Actuarial loss	2,480	1,275
Benefits paid	(1,675)	(945)
Projected benefit obligation at end of year	$ 23,867	$ 18,550
Change in plan assets		
Fair value of plan assets at beginning of year	$ 9,101	$ 6,552
Actual return on plan assets	1,181	1,466
Employer contribution	1,725	2,028
Benefits paid	(1,675)	(945)
Fair value of plan assets at end of year	$ 10,332	$ 9,101
Funded status at end of year	$ (13,535)	$ (9,449)

The Company's funded status for the Pension Plans for the years ended December 31, 2010, and 2009, is $13.5 million and $9.4 million, respectively, and is recognized in the accompanying consolidated balance sheets as a portion of other noncurrent liabilities. No plan assets of the Qualified Pension Plan were returned to the Company during the fiscal year ended December 31, 2010. There are no plan assets in the Nonqualified Pension Plan.

Information for Pension Plan with Accumulated Benefit Obligation in Excess of Plan Assets for Both Plans

	As of December 31,	
	2010	2009
	(in thousands)	
Projected benefit obligation	$ 23,867	$ 18,550
Accumulated benefit obligation	$ 17,457	$ 13,278
Less: Fair value of plan assets	10,332	9,101
Underfunded accumulated benefit obligation	$ 7,125	$ 4,177

Pension expense is determined based upon the annual service cost of benefits (the actuarial cost of benefits earned during a period) and the interest cost on those liabilities, less the expected return on plan assets. The expected long-term rate on plan assets is applied to a calculated value of plan assets that recognizes changes in fair value over a five-year period. This practice is intended to reduce year-to-year volatility in pension expense, but it can have the effect of delaying recognition of differences between actual returns on assets and expected returns based on long-term rate of return assumptions. Amortization of unrecognized net gain or loss resulting from experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of net periodic benefit cost for a year. If, as of the beginning of the year, that unrecognized net gain or loss exceeds ten percent of the greater of the projected benefit obligation and the market-related value of plan assets, the amortization is that excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.

Pre-tax amounts not yet recognized in net periodic pension costs, but rather recognized in accumulated other comprehensive income as of December 31, 2010, and

2009, consist of:

	As of December 31, 2010	As of December 31, 2009
	(in thousands)	
Unrecognized actuarial losses	$ 5,892	$ 4,322
Unrecognized prior service costs	—	—
Unrecognized transition obligation	—	—
Accumulated other comprehensive income	$ 5,892	$ 4,322

The estimated net loss that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is $366,000.

Other pre-tax changes recognized in other comprehensive income during 2010, 2009, and 2008, were as follows:

	As of December 31, 2010	2009	2008
	(in thousands)		
Net actuarial loss	$ (1,937)	$ (239)	$ (2,181)
Less: Amortization of:			
Prior service cost	—	—	—
Actuarial loss	(367)	(358)	(240)
Total other comprehensive income	$ (1,570)	$ 119	$ (1,941)

Components of Net Periodic Benefit Cost for Both Pension Plans

	For the Years Ended December 31, 2010	2009	2008
	(in thousands)		
Components of net periodic benefit cost			
Service cost	$ 3,392	$ 2,500	$ 2,229
Interest cost	1,120	934	889
Expected return on plan assets that reduces periodic pension cost	(638)	(430)	(565)
Amortization of prior service cost	—	—	—
Amortization of net actuarial loss	367	372	248
Net periodic benefit cost	$ 4,241	$ 3,376	$ 2,801

Gains and losses in excess of ten percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Pension Plan Assumptions

Weighted-average assumptions to measure the Company's projected benefit obligation and net periodic benefit cost are as follows:

	As of December 31, 2010	2009	2008
Projected benefit obligation			
Discount rate	5.3%	6.1%	6.6%
Rate of compensation increase	6.2%	6.2%	6.2%
Net periodic benefit cost			
Discount rate	6.1%	6.6%	6.1%
Expected return on plan assets	7.5%	7.5%	7.5%
Rate of compensation increase	6.2%	6.2%	6.2%

The Company's pension investment policy includes various guidelines and procedures designed to ensure that assets are prudently invested in a manner necessary to meet the future benefit obligation of the Pension Plans. The policy does not permit the direct investment of plan assets in the Company's securities. The Company's investment horizon is long-term and accordingly the target asset allocations encompass a strategic, long-term perspective of capital markets, expected risk and return behavior and perceived future economic conditions. The key investment principles of diversification, assessment of risk, and targeting the optimal expected returns for given levels of risk are applied.

The Company's investment portfolio contains a diversified blend of common stocks and bonds, which may reflect varying rates of return. The investments are further diversified within each asset classification. The portfolio diversification provides protection against a single security or class of securities having a disproportionate impact on aggregate investment performance. The actual asset allocations are reviewed and rebalanced on a periodic basis to maintain the target allocations. The Company's weighted-average asset allocation for the Qualified Pension Plan is as follows:

Asset Category	Target 2011	As of December 31, 2010	2009
Equity securities	60%	60.8%	61.3%
Debt securities	40%	39.2%	38.7%
Total	100.0%	100.0%	100.0%

There is no asset allocation of the Nonqualified Pension Plan since there are no plan assets in that plan. An expected return on plan assets of 7.5 percent was used to calculate the Company's obligation under the Qualified Pension Plan for 2010 and 2009. Factors considered in determining the expected return include the 60 percent equity and 40 percent debt securities mix of investment of plan assets and the long-term historical rate of return provided by the equity and debt securities markets. The difference in investment income using the projected rate of return compared to the actual rates of return for the past two years was not material and will not have a material effect on the statements of operations or cash flows from operating activities in future years.

Fair Value Assumptions

The Company's pension plan assets consist of funds that have quoted net asset values within active markets. The individual funds are derived from quoted equity and debt securities within active markets with no judgment involved. As such, the funds are deemed to be Level 1. The fair value of the Company's pension plan assets as of December 31, 2010, utilizing the fair value hierarchy discussed in Note 11 — Fair Value Measurements is as follows:

Assets:	Level 1	Level 2 (in thousands)	Level 3
Cash and Money Market Funds	$ 4	$ —	$ —
Equity Securities			
Foreign Large Blend (1)	1,444	—	—
U.S. Small Blend (2)	1,647	—	—
U.S. Large Blend (3)	3,185	—	—
Fixed Income Securities			
Intermediate Term Bond (4)	4,052	—	—
Total	$ 10,332	$ —	$ —

(1) International equities are invested in companies that trade on active exchanges outside the U.S. and are well diversified among a dozen or more developed markets. Active and passive strategies are employed.

(2) U.S. equities are invested in companies that are well diversified by industry sector and equity style, such as growth and value strategies, that trade on active exchanges within the U.S. Active and passive management strategies are employed. At least 80% of this fund is invested in equity securities of small companies.

(3) U.S. equities include companies that are well diversified by industry sector and equity style, such as growth and value strategies, that trade on active exchanges within the U.S. Active and passive management strategies are employed. At least 80% of this fund is invested in equity securities designed to replicate the holdings and weightings of the stocks listed in the S&P 500 index.

(4) Intermediate term bonds seek total return. At least 80% of this fund is invested in a diversified portfolio of bonds, which include all types of securities. It invests primarily in bonds of corporate and governmental issues located in the U.S. and foreign countries, including emerging markets all of which trade on active exchanges.

The fair value of the Company's pension plan assets as of December 31, 2009, is as follows (see footnotes above):

Assets:	Level 1	Level 2 (in thousands)	Level 3
Cash and Money Market Funds	$ 4	$ —	$ —
Equity Securities			
Foreign Large Blend (1)	1,365	—	—
U.S. Small Blend (2)	1,406	—	—
U.S Large Blend (3)	2,802	—	—
Fixed Income Securities			
Intermediate Term Bond (4)	3,524	—	—
Total	$ 9,101	$ —	$ —

Contributions

The Company contributed $1.7 million, $2.0 million, and $2.5 million, to the Pension Plans in the years ended December 31, 2010, 2009, and 2008, respectively. The Company is required to make a $4.4 million contribution to the Pension Plans in 2011.

Benefit Payments

The Pension Plans made actual benefit payments of $1.7 million, $945,000, and $2.9 million in the years ended December 31, 2010, 2009, and 2008, respectively. Expected benefit payments over the next ten years are as follows (in thousands):

Years Ended December 31,	
2011	$ 1,304
2012	1,377
2013	2,553
2014	2,697
2015	2,151
2016 through 2019	$ 20,512

Note 9 — Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company's accompanying consolidated statements of cash flows.

The Company's estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimates as to the cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company's abandonment liabilities range from 6.5 percent to 12.0 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives or if federal or state regulators enact new requirements regarding the abandonment of wells.

A reconciliation of the Company's asset retirement obligation liability is as follows:

	As of December 31, 2010	As of December 31, 2009
	(in thousands)	
Beginning asset retirement obligation	$ 102,080	$ 116,274
Liabilities incurred	4,738	2,784
Liabilities settled	(30,523)	(28,958)
Accretion expense	5,583	8,673
Revision to estimated cash flows	971	3,307
Ending asset retirement obligation	$ 82,849	$ 102,080

As of December 31, 2010, and 2009, the Company had $2.1 million and $18.1 million, respectively, of asset retirement obligation associated with the oil and gas properties held for sale included in a separate line item on the Company's consolidated balance sheets. Additionally, as of December 31, 2010, and 2009, accounts payable and accrued expenses contain $11.7 million and $23.7 million, respectively, related to the Company's current asset retirement obligation liability associated with the estimated plugging and abandonment costs associated with one offshore platform that was destroyed during Hurricane Ike and multiple Gulf of Mexico platforms that are being relinquished or plugged.

Note 10 — Derivative Financial Instruments

Oil, Natural Gas and NGL Commodity Hedges

To mitigate a portion of the exposure to potentially adverse market changes in oil, gas, and NGL prices and the associated impact on cash flows, the Company has entered into various derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for oil, natural gas, and NGLs. As of December 31, 2010, the Company has hedge contracts in place through the third quarter of 2013 for a total of approximately 6 million Bbls of anticipated crude oil production, 35 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production. As of February 18, 2011, the Company had hedge contracts in place through the fourth quarter of 2013 for a total of approximately 9 million Bbls of anticipated crude oil production, 44 million MMBtu of anticipated natural gas production, and 2 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil, natural gas, and NGL derivative instruments as cash flow hedges for accounting purposes. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company's risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil, natural gas or NGLs. The Company also formally assesses (both at the derivative's inception and on an ongoing basis) whether the derivatives being utilized have been highly effective in offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting for that derivative prospectively. If hedge accounting is discontinued and the derivative remains outstanding, the Company will recognize all subsequent changes in its fair value in the Company's consolidated statements of operations for the period in which the change occurs. As of December 31, 2010, all oil, natural gas, and NGL derivative instruments qualified as cash flow hedges for accounting purposes. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

Effective January 1, 2011 the Company has elected to de-designate all commodity hedges that had previously been designated as cash flow hedges as of December 31, 2010. Also, the Company has elected to discontinue hedge accounting prospectively.

The Company's oil, natural gas, and NGL hedges are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The Company derives internal valuation estimates taking into consideration the counterparties' credit worthiness, the Company's credit worthiness, and the time value of money. Those internal valuations are then compared to the counterparties' mark-to-market statements. The consideration of the factors results in an estimated exit-price for each derivative asset or liability under a market place participant's view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, natural gas, and NGL derivative markets are highly active. The fair value of oil, gas and NGL derivative contracts designated and qualifying as cash flow hedges was a net liability of $52.3 million and $80.9 million at December 31, 2010, and 2009, respectively.

The following table details the fair value of derivatives recorded in the consolidated balance sheets, by category:

	Location on Consolidated Balance Sheets	Fair Value at December 31, 2010	Fair Value at December 31, 2009
		(in thousands)	

Derivative assets designated as cash flow hedges:			
Commodity contracts	Current assets — Derivative asset	$ 43,491	$ 30,295
Commodity contracts	Other noncurrent assets — Derivative asset	18,841	8,251
Total derivative assets designated as cash flow hedges		$ 62,332	$ 38,546
Derivative liabilities designated as cash flow hedges:			
Commodity contracts	Current liabilities — Derivative liability	$ (82,044)	$ (53,929)
Commodity contracts	Noncurrent liabilities — Derivative liability	(32,557)	(65,499)
Total derivative liabilities designated as cash flow hedges		$ (114,601)	$ (119,428)

Realized gains or losses from the settlement of oil, gas and NGL derivative contracts are reported in the total operating revenues section of the accompanying consolidated statements of operations. The Company realized a net gain of $23.5 million, a net gain of $140.6 million, and a net loss of $101.1 million from its oil, gas, and NGL derivative contracts for the years ended December 31, 2010, 2009, and 2008, respectively.

For the years ended December 31, 2010, 2009, and 2008, after-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they were effective in offsetting cash flows attributed to the hedged risk, were recorded in accumulated other comprehensive income in the accompanying consolidated balance sheets until the hedged item was realized in earnings upon the sale of the associated hedged production. When hedges are de-designated from forecasted production, the amount of deferred gain or loss in Accumulated Other Comprehensive Income will freeze and will gradually decrease until the hedges once designated expire and are settled in cash. As of December 31, 2010, the amount of unrealized loss net of deferred income taxes to be reclassified from accumulated other comprehensive income to realized oil and gas hedge gain (loss) in the Company's accompanying consolidated statements of operations in the next twelve months is $13.4 million.

Under cash flow hedge accounting, the Company attempted to minimize ineffectiveness by entering into oil derivative contracts indexed to the New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI") index, natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company's areas of production, and NGL derivative contracts indexed to OPIS Mont Belvieu. As the Company's derivative contracts contain the same index as the Company's sales contracts, this results in derivative contracts that are highly correlated with the underlying hedged item.

The following table details the effect of derivative instruments on other comprehensive income (loss) and the accompanying consolidated balance sheets (net of income tax):

	Derivatives Qualifying as Cash Flow Hedges	Location on Consolidated Balance Sheets	For the Years Ended December 31, 2010	2009	2008
			(in thousands)		
Amount of (gain) loss on derivatives recognized in OCI during the period (effective portion)	Commodity hedges	Accumulated other comprehensive loss	$ (16,811)	$ 35,977	$ (177,005)

The following table details the effect of derivative instruments on other comprehensive income (loss) and the accompanying consolidated statements of operations (net of income tax):

	Derivatives Qualifying as Cash Flow Hedges	Location on Consolidated Statements of Operations	For the Years Ended December 31, 2010	2009	2008
			(in thousands)		
Amount of (gain) loss reclassified from AOCI to realized oil and gas hedge gain (loss) (effective portion)	Commodity hedges	Realized oil and gas hedge gain (loss)	$ 6,641	$ (67,344)	$ 46,463

Any change in fair value resulting from hedge ineffectiveness is recognized in unrealized derivative (gain) loss in the accompanying consolidated statements of operations. The following table details the effect of derivative instruments on the accompanying consolidated statements of operations:

Derivatives Qualifying as Cash Flow Hedges	Location on Consolidated Statements of Operations	(Gain) Loss Recognized in Earnings (Ineffective Portion) For the Years Ended December 31, 2010	2009	2008
		(in thousands)		
Commodity hedges	Unrealized derivative (gain) loss	$ 8,899	$ 20,469	$ (11,209)

Convertible Note Derivative Instrument

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of December 31, 2010 and 2009, the value of this derivative was determined to be immaterial.

Note 11 — Fair Value Measurements

The Company follows fair value measurement authoritative guidance for all assets and liabilities measured at fair value. That guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 — Quoted prices in active markets for identical assets or liabilities
- Level 2 — Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 — Significant inputs to the valuation model are unobservable

The following is a listing of the Company's financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2010:

	Level 1	Level 2	Level 3
		(in thousands)	
Assets:			
Derivatives	$ —	$ 62,332	$ —
Liabilities:			
Derivatives	$ —	$ 114,601	$ —
Net Profits Plan	$ —	$ —	$ 135,850

There were no nonfinancial assets or liabilities measured at fair value on a nonrecurring basis at December 31, 2010.

The following is a listing of the Company's assets and liabilities that are measured at fair value and where they are classified within the hierarchy as of December 31, 2009:

	Level 1	Level 2	Level 3
		(in thousands)	
Assets:			
Derivatives(a)	$ —	$ 38,546	$ —
Proved oil and gas properties(b)	$ —	$ —	$ 11,740
Materials inventory(b)	$ —	$ 13,882	$ —
Liabilities:			
Derivatives(a)	$ —	$ 119,428	$ —
Net Profits Plan(a)	$ —	$ —	$ 170,291

(a) This represents a financial asset or liability that is measured at fair value on a recurring basis.

(b) This represents a nonfinancial asset or liability that is measured at fair value on a nonrecurring basis.

Both financial and non-financial assets and liabilities are categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the hierarchy.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL hedges. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may ask counterparties to post collateral if their ratings deteriorate. In some instances the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current credit facility margins, and any change in such margins since the last measurement date. The majority of the Company's derivative counterparties are members of SM Energy's credit facility bank syndicate.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with accounting authoritative guidance and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. The inputs available for this instrument are unobservable, and therefore classified as Level 3 inputs. The Company employs the income approach, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil and gas commodity prices driving net cash flows and the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and vice versa.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. For those pools currently in payout, a discount rate of 12 percent is used to calculate this liability. A discount rate of 15 percent is being used to calculate the liability for pools that have not reached payout. These rates are intended to represent the best estimate of the present value of expected future payments under the Net Profits Plan.

The Company's estimate of its liability is highly dependent on commodity prices, cost assumptions, and the discount rates used in the calculations. The Company continually evaluates the assumptions used in this calculation in order to consider the current market environment for oil and gas prices, costs, discount rates, and overall market conditions. The Net Profits Plan liability was determined using price assumptions of five one-year strip prices with the fifth year's pricing then carried out indefinitely. The average price was adjusted for realized price differentials and to include the effects of hedging for the percentage of forecasted production hedged in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the crude oil, natural gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at December 31, 2010, would differ by approximately $12 million. A one percentage point decrease in the discount rate would result in an

increase to the liability of approximately $7 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $6 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of the Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value on the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates. The following table reflects the activity for the liabilities measured at fair value using Level 3 inputs:

	For the Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
Beginning balance	$ 170,291	$ 177,366	$ 211,406
Net increase in liability (a)	14,063	13,511	17,421
Net settlements (a) (b)	(48,504)	(20,586)	(51,461)
Transfers in (out) of Level 3	—	—	—
Ending balance	$ 135,850	$ 170,291	$ 177,366

(a) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(b) Settlements represent cash payments made or accrued under the Net Profits Plan. Settlements for the year ended December 31, 2010, 2009, and 2008, include $26.1 million, $724,000, and $15.1 million respectively, of cash payments made related to divestitures.

3.50% Senior Convertible Notes Due 2027

Based on the market price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $351 million and $290 million as of December 31, 2010 and 2009, respectively. The fair value of the embedded contingent interest derivative was zero as of December 31, 2010, and 2009.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company's management. The calculation of the discount rate is a significant management estimate based on the best information available and estimated to be 12 percent for the year ended December 31, 2010. Management believes that the discount rate is representative of current market conditions and includes the following factors: estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on NYMEX strip pricing, adjusted for basis differentials, for the first five years. Future operating costs are also adjusted as deemed appropriate for these estimates. There were no proved oil and gas properties measured at fair value within the accompanying consolidated balance sheets at December 31, 2010. There was $11.7 million of the $1.7 billion of proved oil and gas properties measured at fair value within the accompanying consolidated balance sheets at December 31, 2009.

Materials Inventory

Materials inventory is valued at the lower of cost or market. The Company uses Level 2 inputs to measure the fair value of materials inventory, which is primarily comprised of tubular goods. The Company uses third party market quotes and compares the quotes to the book value of the materials inventory. If the book value exceeds the quoted market price, the Company reduces the book value to the market price. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing materials inventory. There were no materials inventory measured at fair value within the accompanying consolidated balance sheets at

December 31, 2010. There was $13.9 million of the $24.5 million of materials inventory measured at fair value within the accompanying balance sheets at December 31, 2009.

Asset Retirement Obligations

The income valuation technique is utilized by the Company to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value within the accompanying consolidated balance sheets at December 31, 2010 and 2009.

Please refer to Note 10 — Derivative Financial Instruments, Note 9 — Asset Retirement Obligations, and Note 8 — Pension Benefits for more information regarding the Company's hedging instruments, asset retirement obligations, and pension benefits.

Note 12 — Carry and Earning Agreement

On April 29, 2010, the Company entered into a Carry and Earning Agreement (the "CEA"), which effectively provides for a third party to earn 95 percent of SM Energy's interest in approximately 8,400 net acres in a portion of the Company's East Texas Haynesville shale acreage, as well as an interest in several wells and five percent of SM Energy's interest in approximately 23,400 net acres in a separate portion of the Company's Haynesville acreage in East Texas. In exchange for these interests, the third party has agreed to invest $91.3 million to fund the drilling and completion costs of horizontal wells in the portion of the leases where the Company is retaining 95 percent of its interest. Of this, $86.7 million represents SM Energy's carried drilling and completion costs, which is 95 percent of the total well costs to be invested by the third party. The Company received an initial payment of $45.6 million on April 29, 2010, and a final payment of $45.1 million on December 30, 2010, after the completion of the fourth commitment well. Once SM Energy has completed the expenditure of the total carry amount, the parties will share all costs of operations within the area of joint ownership in accordance with their respective ownership interests.

Note 13 — Repurchase and Retirement of Common Stock

Stock Repurchase Program

In July 2006 the Company's Board of Directors approved an increase of 5,473,182 shares to the remaining authorized number of shares that can be repurchased under the Company's original authorization approved in August 1998, for a total number of shares authorized to be repurchased under the plan of 6,000,000. As of the date of this filing, the Company has Board authorization to repurchase up to 3,072,184 shares of common stock. The shares may be repurchased from time to time in open market transactions or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of SM Energy's existing credit facility agreement, provisions under our 6.625 % Senior Notes, and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flows, and borrowings under the credit facility. The details for shares repurchased and retired are summarized as follows:

	For the Years Ended December 31,		
	2010	2009	2008
Number of shares repurchased	—	—	2,135,600
Total purchase price, including commissions	$ —	$ —	$ 77,149,451
Weighted-average price, including commissions	$ —	$ —	$ 36.13
Number of shares retired	—	—	2,945,212
Remaining shares authorized to be repurchased	3,072,184	3,072,184	3,072,184

Note 14 — Oil and Gas Activities

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Years Ended December 31,		
	2010	2009	2008
		(in thousands)	
Development costs	$ 299,308	$ 213,971	$ 581,615
Facility costs (1)	80,328	9,137	5,933
Exploration costs	443,888	154,122	92,199
Acquisitions			
Proved properties	664	76	51,567
Unproved properties — acquisitions of proved properties	—	—	43,274
Unproved properties — other	53,192	41,677	83,078
Total, including asset retirement obligation(2)(3)	$ 877,380	$ 418,983	$ 857,666

(1) Beginning December 31, 2010, facility costs are being disclosed separately within the development section of cost incurred.

(2) Includes capitalized interest of $4.3 million, $1.9 million, and $4.7 million for the years ended December 31, 2010, 2009, and 2008, respectively.

(3) Includes amounts relating to estimated asset retirement obligations of $5.8 million, $(805,000), and $15.4 million for the years ended December 31, 2010, 2009, and 2008, respectively.

Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2010, 2009, and 2008. The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same period:

	For the Years Ended December 31, 2010	2009	2008
	(in thousands)		
Beginning balance on January 1,	$ 34,384	$ 9,437	$ 42,930
Additions to capitalized exploratory well costs pending the determination of proved reserves	35,862	34,384	9,437
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(34,384)	(7,569)	(36,842)
Capitalized exploratory well costs charged to expense	—	(1,868)	(6,088)
Ending balance at December 31,	$ 35,862	$ 34,384	$ 9,437

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for more than one year since the completion of drilling:

	For the Years Ended December 31, 2010	2009	2008
	(in thousands)		
Exploratory well costs capitalized for one year or less	$35,862	$34,384	$9,437
Exploratory well costs capitalized for more than one year	—	—	—
Ending balance at December 31,	$35,862	$34,384	$9,437
Number of projects with exploratory well costs that have been capitalized more than a year	—	—	—

Note 15 — Disclosures about Oil and Gas Producing Activities (Unaudited)

Oil and Gas Reserve Quantities

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids, 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. With respect to reserves as of dates prior to December 31, 2009, the applicable SEC definition of proved reserves was the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, meaning prices and costs as of the date the estimate is made. All of the Company's proved reserves are located in North America.

The Company emphasizes that reserve estimates are inherently imprecise and that estimates of 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 future information becomes available.

Presented below is a summary of the changes in estimated proved reserves of the Company:

	2010 Oil or Condensate (MMBbl)	2010 Gas (Bcf)	2009 Oil or Condensate (MMBbl)	2009 Gas (Bcf)	2008 Oil or Condensate (MMBbl)	2008 Gas (Bcf)
Total Proved Reserves						
Beginning of year	53.8	449.5	51.4	557.4	78.8	613.5
Revisions of previous estimate(a)	3.1	6.1	4.5	(76.8)	(22.6)	(108.3)
Discoveries and extensions	16.2	172.9	3.4	51.9	0.7	41.1
Infill reserves in an existing proved field	2.8	97.2	1.2	29.9	5.4	92.4
Purchases of minerals in place	—	0.2	—	—	0.4	27.0
Sales of reserves (b)	(12.1)	(14.0)	(0.4)	(41.8)	(4.7)	(33.4)
Production	(6.4)	(71.9)	(6.3)	(71.1)	(6.6)	(74.9)
End of year	57.4	640.0	53.8	449.5	51.4	557.4
Proved developed reserves						
Beginning of year	48.1	342.0	47.1	433.2	68.3	426.6
End of year	46.0	411.0	48.1	342.0	47.1	433.2

Proved undeveloped reserves						
Beginning of year	5.7	107.5	4.3	124.2	10.6	186.8
End of year	11.4	229.0	5.7	107.5	4.3	124.2

(a) For the year ended December 31, 2010, of the 24.7 BCFE upward revision of previous estimate, 42.6 BCFE and (17.9) BCFE relate to price and performance revisions, respectively. 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 the company 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, the Company reduced estimated proved reserves by 6.7 BCFE by removing proved undeveloped reserves related to assets that reached aging limitations, as mandated by the SEC. For the year ended December 31, 2009, of the 49.6 BCFE downward revision of previous estimate, 12.0 BCFE and (61.6) BCFE relate to price and performance revisions, respectively. The largest portion of the performance revision related to producing properties in the Company's Wolfberry tight oil program in the Permian Basin in West Texas. The Company also saw a downward performance revision related to certain Cotton Valley assets in our ArkLaTex region. For the year ended December 31, 2008, of the 244.2 BCFE downward revision of previous estimate, 199.7 BCFE and 44.5 BCFE relate to price and performance revisions, respectively.

(b) The Company divested of certain non-core assets during 2010, 2009, and 2008. Please refer to Note 3 - Divestitures and Assets Held for Sale for additional information.

(c) For the years ended December 31, 2010, 2009, and 2008, amounts included approximately 356, 370, and 659 MMcf respectively, representing the Company's net underproduced gas balancing position.

Standardized Measure of Discounted Future Net Cash Flows

The Company follows applicable authoritative accounting guidance for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated quantities of oil and gas to be produced in the future. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are

computed using the current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a ten percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved oil and gas reserves in place at the end of the period using year-end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. The following prices as adjusted for transportation, quality, and basis differentials were used in the calculation of the standardized measure:

	2010	2009	2008
Gas (per Mcf)	$ 5.54	$ 3.82	$ 4.88
Oil (per Bbl)	$ 70.60	$ 53.94	$ 33.91

The following summary sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure.

	As of December 31,		
	2010	2009	2008
	(in thousands)		
Future cash inflows	$ 7,598,159	$ 4,620,735	$ 4,463,894
Future production costs	(2,512,091)	(1,968,096)	(1,866,821)
Future development costs	(789,493)	(387,722)	(393,620)
Future income taxes	(1,335,576)	(515,953)	(419,544)
Future net cash flows	2,960,999	1,748,964	1,783,909
10 percent annual discount	(1,294,632)	(732,997)	(724,840)
Standardized measure of discounted future net cash flows	$ 1,666,367	$ 1,015,967	$ 1,059,069

The principle sources of change in the standardized measure of discounted future net cash flows are:

	For the Years Ended December 31,		
	2010	2009	2008
	(in thousands)		

Standardized measure, beginning of year	$ 1,015,967	$ 1,059,069	$ 2,706,914
Sales of oil and gas produced, net of production costs	(641,213)	(409,153)	(988,045)
Net changes in prices and production costs	557,681	154,008	(2,033,674)
Extensions, discoveries and other including infill reserves in an existing proved field, net of production costs	989,365	166,666	288,162
Purchase of minerals in place	804	—	33,215
Development costs incurred during the year	43,900	33,742	105,031
Changes in estimated future development costs	49,531	75,134	213,554
Revisions of previous quantity estimates	66,759	(96,354)	(363,908)
Accretion of discount	128,408	126,538	386,118
Sales of reserves in place	(151,315)	(44,823)	(198,514)
Net change in income taxes	(409,848)	(61,801)	947,955
Changes in timing and other	16,328	12,941	(37,739)
Standardized measure, end of year	$ 1,666,367	$ 1,015,967	$ 1,059,069

Note 16 — Quarterly Financial Information (Unaudited)

The Company's quarterly financial information for fiscal 2010 and 2009 is as follows (in thousands, except per share amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2010				
Total operating revenues	$ 360,135	$ 211,697	$ 226,884	$ 294,118
Total operating expenses	152,384	174,908	195,832	230,939
Income from operations	$ 207,751	$ 36,789	$ 31,052	$ 63,179
Income before income taxes	$ 201,093	$ 30,500	$ 24,798	$ 58,505
Net income	$ 126,178	$ 18,068	$ 15,452	$ 37,139
Basic net income per common share	$ 2.01	$ 0.29	$ 0.25	$ 0.59
Diluted net income per common share	$ 1.96	$ 0.28	$ 0.24	$ 0.56
Dividends declared per common share	$ 0.05	$ —	$ 0.05	$ —
Year Ended December 31, 2009				
Total operating revenues	$ 199,220	$ 205,198	$ 185,787	$ 241,996
Total operating expenses	334,685	211,059	185,330	231,962
Income (loss) from operations	$ (135,465)	$ (5,861)	$ 457	$ 10,034
Income (loss) before income taxes	$ (141,539)	$ (13,419)	$ (7,018)	$ 2,512
Net income (loss)	$ (87,623)	$ (8,322)	$ (4,415)	$ 990
Basic net income (loss) per common share	$ (1.41)	$ (0.13)	$ (0.07)	$ 0.02
Diluted net income (loss) per common share	$ (1.41)	$ (0.13)	$ (0.07)	$ 0.02
Dividends declared per common share	$ 0.05	$ —	$ 0.05	$ —

SIGNATURES

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

SM ENERGY COMPANY
(Registrant)

Date: February 25, 2011

By: /s/ ANTHONY J. BEST
Anthony J. Best
President, Chief Executive Officer,
and Director

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Anthony J. Best and A. Wade Pursell his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2010, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ ANTHONY J. BEST Anthony J. Best	President and Chief Executive Officer	February 25, 2011
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer	February 25, 2011
/s/ MARK T. SOLOMON Mark T. Solomon	Controller	February 25, 2011
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Chairman of the Board of Directors	February 25, 2011

Signature	Title	Date
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 25, 2011
/s/ LARRY W. BICKLE Larry W. Bickle	Director	February 25, 2011
/s/ WILLIAM J. GARDINER William J. Gardiner	Director	February 25, 2011
/s/ JULIO M. QUINTANA Julio M. Quintana	Director	February 25, 2011
/s/ JOHN M. SEIDL John M. Seidl	Director	February 25, 2011

EXHIBIT 10.28

AMENDMENT TO
EMPLOYMENT AGREEMENT

This Amendment to Employment Agreement is entered into this 31st day of December, 2010 between SM Energy Company (f/k/a St. Mary Land & Exploration Company), a Delaware corporation ("SM Energy"), and Anthony J. Best ("Best"). It amends the Employment Agreement between SM Energy and Best dated May 1, 2006.

1. Amendment to Agreement. The last sentence of Section 10 is hereby deleted and replaced with the following two sentences:

In particular, with respect to the severance payments provided for under Section 9 of this Agreement, such severance payments that would otherwise be made during the Section 409A Six-Month Waiting Period shall be paid in one lump sum upon the expiration of the Section 409A Six-Month Waiting Period, together with simple interest on the amount of each deferred payment at the short term applicable federal rate as of the date of the separation of Best from employment. For purposes of this Agreement, "termination of employment," "separation from service" or similar language means separation from service by Best from SM Energy for any reason whatsoever within the meaning of Code Section 409A and Treasury Regulation § 1.409A-1(h).

2. Incorporation of Amendment and Remainder of Agreement. The terms and provisions of Section 1 of this Amendment are hereby incorporated into the Agreement and, except for the amendment provisions herein contained, all of the terms and provisions of the Agreement shall remain in full force and effect, unaltered and unchanged by this Amendment. To the extent that the terms and provisions of this Amendment conflict with the terms and provisions of the Agreement, the terms and provisions of this Amendment shall control.

3. Execution in Counterparts and Delivery of Signature Pages. This Amendment may be executed in counterparts and signature pages may be delivered by email or facsimile transmission.

IN WITNESS WHEREOF, this Amendment to the Employment Agreement is hereby duly executed by each party on this 31st day of December, 2010.

AGREED:

SM ENERGY COMPANY,
a Delaware corporation

By: /s/ JOHN R MONARK
John R. Monark, Vice President-Human Resources

By: /s/ ANTHONY J. BEST
Anthony J. Best, CEO & President

EXHIBIT 10.30

PENSION PLAN FOR EMPLOYEES

OF

SM ENERGY COMPANY

AMENDED AND RESTATED

EFFECTIVE AS OF JANUARY 1, 2010

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GENERAL PROVISIONS

WHEREAS, St. Mary Land & Exploration Company adopted the Pension Plan for Employees of St. Mary Land & Exploration Company, effective January 1, 1977 for certain of its employees; and

WHEREAS, the Pension Plan for Employees of St. Mary Land & Exploration Company has been amended from time to time, and was amended in its entirety and restated, effective January 1, 1997; and

WHEREAS, St. Mary Land & Exploration Company changed its name to SM Energy Company, effective June 1, 2010 (the “Company”); and

WHEREAS, the Company desires at this time to rename the Pension Plan for Employees of St. Mary land & Exploration Company as the Pension Plan for Employees of SM Energy, effective June 1, 2010 (the “Plan”); and

WHEREAS, the Company desires at this time to amend and restate the Plan in its entirety to incorporate all amendments since the Plan was most recently restated, and to reflect the 2009 Cumulative List of Changes in Plan Qualification Requirements, as set forth in Notice 2009-98;

NOW, THEREFORE, effective as of January 1, 2010 (except as otherwise set forth herein), the Plan is continued, amended, and restated as hereinafter set forth:

ARTICLE I

DEFINITIONS

Except where otherwise clearly indicated by context, the masculine shall include the feminine and the singular shall include the plural, and vice-versa. Any term used herein without an initial capital letter that is used in a provision of the Code with which this Plan must comply to meet the requirements of section 401(a) of the Code shall be interpreted as having the meaning used in such provision of the Code, if necessary for the Plan to comply with such provision.

"Accrued Benefit" means, for any Participant as of any date, subject to Section 5.10, the amount of annual benefit earned to such date, payable monthly as a single life annuity beginning at the Participant's Normal Retirement Date (or immediately, if the Participant has passed his Normal Retirement Date and is still an Employee) calculated in accordance with Section 5.1.

"Active Participant" means an Employee who has met the conditions to be an Active Participant under Section 2.2 and a Participant who is a Covered Employee as of any date of determination.

"Actuarial Equivalent" or "Actuarially Equivalent" shall mean a benefit having the same present or commuted value as the benefit to which comparison is being made, computed on the basis of the following assumptions:

(a) Except as provided in Subsection (b) below, the 1971 Group Annuity Mortality Table and an interest rate assumption of 6.5%.

(b) Notwithstanding Subsection (a) above, the Actuarial Equivalent value of a single sum payment shall be computed on the basis of:

(1) For any single sum payment with a Benefit Commencement Date on or after the GATT Effective Date and before January 1, 2008, the following factors shall be used to calculate the Actuarial Equivalent value of a single sum payment:

(A) The single sum amount will be the present value of the normal form of benefit payable at the Participant's Normal Retirement Date, as defined in the Plan. The value of subsidized early retirement benefits and optional forms of payment, including the qualified joint and survivor option, will be ignored in determining the amount of a single sum amount;

(B) The applicable mortality table shall be the mortality table described in Rev. Rul. 95-6 (1995-1 C.B. 80), or any other table as the Treasury Secretary may in the future require (the 'Section 417 Mortality Table').

(C) The applicable interest rate shall be the annual rate of interest on 30-year Treasury securities as specified by the Commissioner for the first calendar month prior to the Plan Year that contains the Benefit Commencement Date (the 'Section 417 Interest Rate'), which shall remain stable for such Plan Year."

(2) For any single sum payment with a Benefit Commencement Date on or after January 1, 2008, the following factors shall be used to calculate the Actuarial Equivalent value of a single sum payment:

(A) the single sum amount will be the present value of the normal form of benefit payable at the Participant's Normal Retirement Date, as defined in the Plan. The value of subsidized early retirement benefits and optional forms of payment, including

the qualified joint and survivor option, will be ignored in determining the amount of a single sum amount;

(B) the applicable mortality table shall be the mortality table prescribed by the Secretary of the Treasury in accordance with Code section 417(e)(3) and the regulations thereunder. For distributions commencing on or after January 1, 2008, the applicable mortality table is the table prescribed in Rev. Rul. 2007-67 or other such mortality table as may subsequently be in effect; and

(C) the applicable interest rate shall be:

(i) For distributions commencing on or after January 1, 2008, the adjusted first, second, and third segment rates applied under rules similar to the rules of section 430(h)(2)(C) of the Code for the first calendar month prior to the Plan Year that contains the Benefit Commencement Date (or such other time as the Secretary of the Treasury may prescribe), as described in section 417(e)(3) of the Code and as published from time to time by the Secretary of the Treasury.

(ii) Notwithstanding the foregoing, for distributions commencing during the Plan Year beginning January 1, 2008, 2009, 2010 or 2011, the applicable interest rate shall be the sum of the rate determined under Subparagraph (1)(C), above, multiplied by the applicable percentage, and the rate determined under Subparagraph (2)(C)(i), above, multiplied by one hundred percent (100%) minus the applicable percentage as set forth below:

Plan Year	**Applicable Percentage**	**100% Minus Applicable Percentage**
January 1, 2008	80%	20%
January 1, 2009	60%	40%
January 1, 2010	40%	60%
January 1, 2011	20%	80%

"Actuary" means the actuarial firm or individual selected by the Committee from time to time.

"Administrator" means the Committee or any successor committee, entity or individual(s) if any, to whom the Company has delegated administrative responsibilities under the Plan.

"Affiliated Company" means, with respect to any Participating Company, (a) any corporation that is a member of the same controlled group of corporations (within the meaning of section 414(b) of the Code) as such Participating Company; (b) any member of an affiliated service group, as determined under section 414(m) of the Code, of which such Participating Company is a member; (c) any trade or business that is under common control with such Participating Company, as determined under section 414(c) of the Code and (d) any other entity which is required to be aggregated with a Participating Company under section 414(o) of the Code. "50% Affiliated Company" means an Affiliated Company, but determined with "more than 50%" substituted for the phrase "at least 80%" in section 1563(a) of the Code, when applying sections 414(b) and 414(c) of the Code.

"Age" means, for any individual, his age on last birthday, except that an individual attains Age 70½ on the corresponding date in the sixth calendar month following the month in which his 70th birthday falls (or the last day of such sixth month if there is no such corresponding date therein).

"Benefit Commencement Date" means, for any Participant, the date as of which his first benefit payment is due. For purposes of Section 5.8 and for purposes of Paragraph (3) of

Subsection 5.10(a), in calculating the maximum benefit payable to the Surviving Spouse of a Participant under Section 5.8 or to the beneficiary of a Participant under Section 5.7, "Benefit Commencement Date" also means, with respect to the Surviving Spouse or beneficiary, the date on which the survivor's benefit under Section 5.8 commences to the Surviving Spouse or the date on which benefits are paid to the beneficiary under Section 5.7.

"Board of Directors" means the board of directors of the Company, or a Committee of the Board of Directors to which the Board of Directors has delegated some or all of its responsibilities hereunder.

"Break in Service" means, for any Employee or former Employee, any Computation Period in which he is not credited with more than 500 Hours of Service.

(a) Notwithstanding the foregoing, if an Employee is absent for leave of absence with the approval of the Committee for a period not in excess of one year, unless such period is extended by the Committee, then, to the extent he is not otherwise credited with Hours of Service with respect to such absence, he shall be credited with an Hour of Service, solely for purposes of this definition, for each Hour of Service with which he would have been credited if he had continued to be actively employed during the period of absence.

(b) Notwithstanding the foregoing, if an Employee is absent from work by reason of pregnancy, childbirth, or placement in connection with adoption, or for purposes of the care of such Employee's child immediately after birth or placement in connection with adoption, such Employee shall not have a Break in Service during the first Computation Period in which the Employee would otherwise have a Break in Service pursuant to the rules set forth in Subsection (a) of this Section.

"Code" means the Internal Revenue Code of 1986, as amended.

"Committee" means the individuals appointed by the Board of Directors to serve on the Administrative Committee of the Plan, or any other successor committee or individual(s), to supervise the administration of the Plan, as provided in Article IX.

"Company" means St. Mary Land & Exploration Company prior to June 1, 2010, and effective on and after June 1, 2010, SM Energy Company and its successors.

"Compensation" means, for any Active Participant, for any Plan Year or imitation Year, as the case may be:

(a) For purposes of calculating a Participant's Accrued Benefit under Article V, subject to the limitations set forth in Subsection (c) of this definition, the amount of his total taxable income paid by a Participating Company in any Plan Year, including Differential Wage Pay, if any, less bonuses, director's fee, expense reimbursements, contributions by the Company to this Plan, payments made by the Company for group insurance, hospitalization and similar benefits, contributions made by the Company under any other employee benefit plan it maintains, except Compensation shall include elective deferrals that are not included in gross income under section 125, 132(f)(4), 402(e)(3), or 402(h) of the Code, taking into account only amounts earned while he is an Active Participant. An Active Participant's Compensation shall not include amounts that are taxable to him but are not paid to him in cash.

(b) For all other purposes, subject to the limitations set forth in Subsection (c) of this definition, his "compensation" as such word is defined in Treas. Reg. § 1.415(c)-2(d)(2).

(c) The amount otherwise described in Subsections (a) and (b) of this definition shall not exceed $245,000, as such limit may be adjusted in accordance with section

401(a)(17)(B) of the Code. In applying the limit of Code section 401(a)(17) to any Participant who was a Participant at any time prior to January 1, 1994 and whose Compensation with respect to any Plan Year beginning prior to January 1, 1994 exceeded $150,000, such Participant's Accrued Benefit shall be calculated according to the rules set forth in Subsection 5.1(c).

"Computation Period" means the 12-consecutive month period that begins on each January 1st and ends on the next following December 31st.

"Covered Compensation" means the amount determined using the following table based on the amount applicable for the calendar year in which the later of the Effective Date or the Participant's 65th birthday occurs:

Calendar Year of 65th Birthday	**Amount**
1985	$ 13,800
1986	15,000
1987	15,600
1988	16,200
1989	17,400
1990	18,000
1991	18,600
1992	19,200
1993	19,800
1994	20,400
1995	21,600
1996	22,200
1997	23,400
1998	24,600
1999	25,200
2000	26,400
2001	27,600
2002	28,200
2003	29,400
2004	30,000
2005	31,200
2006	31,800
2007	33,000
2008	33,600
2009	34,800
2010	35,400
2011	36,000
2012	36,600
2013	37,200
2014	37,800
2015	38,400
2016	39,000
2017	39,000
2018	39,000
2019	39,600
2020 and later	39,600

The foregoing table is the average wage used to determine benefits under the Social Security Act in effect for retirements or terminations of employment during 1983 for a

male individual of the same birth year as the Participant receiving compensation continuously to age 65 at least equal to the maximum amount subject to the Federal Insurance Contributions Act. This table shall be updated without further Plan amendment for each Plan Year after 1983 to reflect the maximum amount of wages subject to the Federal Insurance Contributions Act in such Plan Year.

"Covered Employee" means each Employee who (a) is classified by a Participating Company as a common law employee of such a Participating Company, and (b) is not covered by a collective bargaining agreement, unless such agreement specifically provides for participation hereunder, and (c) is not covered by another qualified defined benefit pension plan to which the Participating Company makes contributions and (d) is not a non-resident alien who receives no compensation from sources within the United States (within the meaning of section 861(a)(3) of the Code). An individual who is a member of the Company's Board of Directors and is not employed by the Company in any other capacity shall not be a Covered Employee. An Individual who is a property agent with respect to the Company and is not otherwise employed by the Company shall not be a Covered Employee. An individual who is not classified by a Participating Company as a common law employee shall not be a Covered Employee regardless of whether (1) the individual is considered an Employee by reason of being a leased employee (whether or not within the meaning of the definition of Leased Employee in this Article), (2) the individual is classified by a Participating Company as an independent contractor, or (3) for employment tax or other purposes, the individual is subsequently determined to be a common law employee, or not to be a leased employee (whether or not within the meaning of the definition of Leased Employee in this Article) or independent contractor. For purposes of determining eligibility under the Plan, the classification to which an individual is

assigned by a Participating Company shall be final and conclusive, regardless of whether a court, a governmental agency or any entity subsequently finds that such individual should have been assigned to a different classification.

"Differential Wage Pay" means any payment which:

(a) is made by the Company to a Participant with respect to any period during which the Participant is performing service in the uniformed services (as defined in chapter 43 of title 38, United States Code) while on active duty for a period of more than 30 days, and

(b) represents all or a portion of the wages the Participant would have received from the Company if the Participant were performing service for the Company.

"Disability Retirement Date" means, for any Participant, the date on which he (a) is determined by the Committee to have suffered a Total Disability, and (b) has a Separation from Service due to such Total Disability; provided, however, that a Participant shall not have a Disability Retirement Date unless, at the time his Total Disability occurs, he is an Employee, and has to his credit 10 or more Years of Credited Service.

"Disabled Participant" means a Participant who has a Disability Retirement Date that occurs prior to his Normal Retirement Date and who has not ceased to be a Disabled Participant pursuant to Section 4.4(c).

"Early Retirement Date" means, for any Participant, the first day of the calendar month coincident with or next following the date on which he has a Separation from Service after he has attained Age 55 and has to his credit 10 or more Years of Credited Service.

"Effective Date" means (except as otherwise set forth herein) January 1, 2010, the effective date of this amended and restated Plan.

"Employee" means an individual who is a common law employee of a Participating Company or an Affiliated Company. An individual who is not a common law employee of a Participating Company or Affiliated Company shall be deemed to be employed by such Company if he is a leased employee with respect to whose services such Participating Company or Affiliated Company is the recipient within the meaning of Code section 414(n) or 414(o), but to whom Code section 414(n)(5) does not apply. An individual who is in receipt of Differential Wage Pay shall be deemed to be an Employee during such period, provided that he was an Employee immediately prior to such period.

"Employment Commencement Date" means, for any Employee, the date on which he is first entitled to be credited with an "Hour of Service" described in Paragraph (a)(1) of the definition of Hour of Service in this Article.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

"Final Average Compensation" means, for any Participant, the average of his Compensation for the three full consecutive calendar years in the final 10 (or fewer) full consecutive calendar years of employment as an Active Participant which yields the highest average. For this purpose, nonconsecutive calendar years interrupted by periods in which the Participant is not an Active Participant shall be treated as consecutive. If a Participant does not have three full consecutive calendar years of employment as an Active Participant, his Final Average Compensation shall be the annual amount determined by dividing his Compensation during the period in which he is an Active Participant by the number of years thereof.

"Fund" means the fund established for this Plan, administered under the Trust Agreement, out of which benefits payable under this Plan shall be paid.

"Hour of Service" means, for any Employee, a credit awarded with respect to:

(a) except as provided in (b) or (c),

(1) each hour for which he is directly or indirectly paid or entitled to payment by a Participating Company or an Affiliated Company for the performance of employment duties; or

(2) each hour for which he is entitled, either by award or agreement, to back pay from a Participating Company or an Affiliated Company, irrespective of mitigation of damages; or

(3) each hour for which he is directly or indirectly paid or entitled to payment by a Participating Company or an Affiliated Company on account of a period of time during which no duties are performed due to vacation, holiday, illness, incapacity (including disability), jury duty, layoff, leave of absence, or military duty; or

(4) each hour for which a Returning Veteran is absent for Qualified Military Service.

(5) each hour of otherwise regularly scheduled work missed by reason of Total Disability during which the Employee is a Disabled Participant.

(b) For any period that includes any hours for which an Hour of Service would otherwise be credited to an Employee under (a), above, the Committee may, in accordance with rules applied in a uniform and non-discriminatory manner, elect instead to credit Hours of Service using one or more of the following equivalencies:

Basis Upon Which Records Are Maintained	**Credit Granted to Individual For Period**
Shift	actual hours for full shift
Day	10 Hours of Service
Week	45 Hours of Service
Semi-monthly period	95 Hours of Service
Month	190 Hours of Service

(c) Anything to the contrary in Subsection (a) or (b) notwithstanding:

(1) No Hours of Service shall be credited to an Employee for any period during which payments are made or due him under a plan maintained solely for the purpose of complying with applicable workers' compensation, unemployment compensation, or disability insurance laws.

(2) No more than 501 Hours of Service shall be credited to an Employee under Paragraph (a)(3) of this definition on account of any single continuous period during which no duties are performed by him, except to the extent otherwise provided in the Plan.

(3) No Hours of Service shall be credited to an Employee with respect to payments solely to reimburse for medical or medically related expenses.

(4) No Hours of Service shall be credited twice.

(5) Hours of Service shall be credited at least as liberally as required by the rules set forth in U.S. Department of Labor Reg. §2530.200b-2(b) and (c).

(6) In the case of an Employee who is such solely by reason of service as a leased employee within the meaning of section 414(n) or 414(o) of the Code, Hours of Service shall be credited as if such Employee were employed and paid with respect to such service (or with respect to any related absences or entitlements) by the Participating Company or Affiliated Company that is the recipient thereof.

"Late Retirement Date" means, for any Participant, the first day of the calendar month coincident with or next following the date on which he has a Separation from Service, if such Separation from Service occurs after the Participant's Normal Retirement Date.

"Leased Employee" means any person (other than an Employee of a Participating Company or Affiliated Company) who pursuant to an agreement between a Participating Company or Affiliated Company and any other person ("leasing organization") has performed services for a Participating Company or Affiliated Company (or for a Participating Company or Affiliated Company and related persons determined in accordance with section 414(n)(6) of the Code) on a substantially full time basis for a period of at least one year, which services are performed under primary direction or control of a Participating Company or Affiliated Company.

A Leased Employee shall not be considered an Employee of a Participating Company or Affiliated Company if (a) such individual is covered by a money purchase pension plan maintained by the leasing organization and providing (1) a nonintegrated employer contribution rate of at least 10 percent of compensation, as defined in section 415(c)(3) of the Code, but including amounts contributed pursuant to a salary reduction agreement which are excludable from the employee's gross income under section 125, section 132(f)(4), section 402(e)(3), section 402(h)(1)(B) or section 403(b) of the Code, (2) immediate participation, and (3) full and immediate vesting; and (b) leased employees do not constitute more than 20 percent of the recipient's nonhighly compensated work force.

"Limitation Year" means the Plan Year.

"Normal Retirement Date" means, for any Participant, the first day of the calendar month coincident with or next following the date on which he attains Age 65.

"Participant" means an individual who is an Active Participant, a former Active Participant receiving benefits under the Plan, a former Active Participant who has a present or future right to receive benefits under the Plan, or an Employee who was once an Active Participant and has been transferred so that he is no longer a Covered Employee.

"Participating Company" means the Company and each other organization which is authorized by the Board of Directors to adopt this Plan by action of its board of directors or other governing body.

"Plan" means the Pension Plan for Employees of St. Mary Land & Exploration Company prior to June 1, 2010, and effective on and after June 1, 2010, the Pension Plan for Employees of SM Energy Company, as set forth herein (including any Schedules).

"Plan Year" means each 12-consecutive month period that begins on January 1, or any anniversary thereof and ends on the next following December 31.

"Predecessor Company" means, with respect to any Participating Company or Affiliated Company, any corporation to which such Participating Company or Affiliated Company is a successor in interest by merger, consolidation, asset acquisition, stock acquisition, or reincorporation, and any other corporation designated as such for purposes of this Plan by the Board of Directors.

"Qualified Military Service" means any service (either voluntary or involuntary) by an individual in the Uniformed Services if such individual is entitled to reemployment rights with a Participating Company with respect to such service.

"Required Beginning Date" means, for any Participant:

(a) if he attains Age 70½ on or after January 1, 2002 and is not a 5-percent owner (within the meaning of section 416 of the Code) of a Participating Company at

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any time during the five-Plan-Year period ending in the calendar year in which he attains Age 70½, or thereafter, April 1 of the calendar year following the later of the calendar year in which he has a Separation from Service or the calendar year in which he attains Age 70½; and

(b) if he attains Age 70½ after December 31, 1987 and was a 5-percent owner (within the meaning of section 416 of the Code) of a Participating Company at any time during the five-Plan Year period ending in the calendar year in which he attained Age 70½, or thereafter, April 1 of the calendar year following the calendar year in which he attains Age 70½;

"Returning Veteran" means a former Employee who on or after December 12, 1994, returns from Qualified Military Service to employment by a Participating Company within the period of time during which his reemployment rights are protected by law.

"Separation from Service" means, for any Employee, his death, retirement, resignation, discharge or any absence that causes him to cease to be an Employee.

"Social Security Retirement Age" means (a) for any individual born before January 1, 1938, Age 65, (b) for any individual born after December 31, 1937, but before January 1, 1955, Age 66, or (c) for any individual born after December 31, 1954, Age 67.

"Spouse" means, with respect to any Participant, the individual to whom such Participant is married as of the date of reference.

"Surviving Spouse" means, with respect to any Participant:

(a) for purposes of the survivor's benefit described in Section 5.8, the individual, if any, who has been such Participant's Spouse throughout the one-year period that ends on the date of the Participant's death; and

(b) for purposes of the joint and survivor annuity described in Section 7.2(b) the individual, if any, who is such Participant's Spouse on the Participant's Benefit Commencement Date.

"Total Disability" means, with respect to any Participant, inability to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or which has lasted or can be expected to last for a continuous period of not less than 12 months. The permanence and degree of such impairment shall be supported by medical evidence.

"Trust Agreement" means the agreement and declaration of trust executed for purposes of the Plan.

"Trustee" means the corporate trustee or one or more individuals collectively appointed and acting under the Trust Agreement.

"Uniformed Services" means the Armed Forces, the Army National Guard and Air National Guard (when engaged in active duty for training, inactive duty training, or full-time National Guard duty), the commissioned corps of the Public Health Service, and any other category of persons designated by the President of the United States in time of war or emergency.

"Year of Credited Service" means, for any Participant, a credit used to determine his Accrued Benefit under the Plan, as further described in Article III.

"Year of Eligibility Service" means, for any Employee, a credit used to determine his eligibility to become an Active Participant, as further described in Section 2.3.

"Year of Vesting Service" means, for any Employee, a credit used to determine his vested status under the Plan, as further described in Article III.

ARTICLE II

TRANSITION AND ELIGIBILITY TO PARTICIPATE

2.1 Rights Affected and Preservation of Accrued Benefit. Except as provided to the contrary herein, the provisions of this amended and restated Plan shall apply only to Employees who complete an Hour of Service on or after the Effective Date. The rights of any other individual shall be governed by the Plan as in effect upon his Separation from Service, except to the extent expressly provided in any amendment adopted subsequently thereto.

2.2 Eligibility to Participate.

(a) Each Employee who was an Active Participant immediately prior to the Effective Date and is a Covered Employee on the Effective Date shall continue to be an Active Participant as of the Effective Date. Each Employee who was not an Active Participant immediately prior to the Effective Date and who has attained Age 21 and completed one Year of Eligibility Service as of the Effective Date shall become an Active Participant as of the Effective Date if he is then a Covered Employee. Each other Employee shall become an Active Participant on the first day of the calendar month coincident with or next following the date on which he attains Age 21 and completes one Year of Eligibility Service, if he is then a Covered Employee.

(b) A Participant (or a former Participant) who has a Separation from Service and who is later reemployed as a Covered Employee shall become an Active Participant as of the date on which he first again completes an Hour of Service as a Covered Employee, but, if he has had a Break in Service, only if he (1) had any nonforfeitable interest in his Accrued Benefit as of his prior Separation from Service or (2) again completes one Hour of Service at a

time when his consecutive Breaks in Service do not equal or exceed the greater of (A) five or (B) the number of Years of Eligibility Service he had to his credit prior to his Break in Service.

(c) If an individual is not a Covered Employee on the date on which he would become an Active Participant (but for the fact that he is not then a Covered Employee), he shall become an Active Participant as of the first date thereafter on which he becomes a Covered Employee; but, if he has had a Break in Service, only if he (1) had any nonforfeitable interest in his Accrued Benefit as of his prior Separation from Service or (2) he again completes one Hour of Service at a time when his consecutive Breaks in Service do not equal or exceed the greater of (A) five or (B) the number of Years of Eligibility Service he had to his credit prior to his Break in Service.

2.3 Year of Eligibility Service. An Employee shall be credited with a Year of Eligibility Service as of the close of the 12-consecutive-month period that begins on his Employment Commencement Date if he is credited with 1,000 or more Hours of Service during such period. An Employee who is not credited with 1,000 Hours of Service during such period shall be credited with a Year of Eligibility Service as of the close of the first Plan Year in which he is credited with 1,000 or more Hours of Service. Notwithstanding the foregoing, an Employee shall be credited with a Year of Eligibility Service for service with The Five-Twenty Company.

ARTICLE III

VESTING SERVICE AND CREDITED SERVICE

3.1 Years of Vesting Service. Each Employee shall be credited with a Year of Vesting Service for each Computation Period, including Computation Periods ended before January 1, 1977, the original effective date of the Plan, for which he is credited with 1,000 or more Hours of Service.

3.2 Years of Credited Service.

(a) Except as provided in this Article, a Participant shall be credited with a Year of Credited Service for each Computation Period for which he is credited with 1,000 or more Hours of Service. For the purpose of calculating a Participant's Years of Credited Service, only Hours of Service credited for a period during which he is (or, in the case of back pay, would have been) a Covered Employee or a Disabled Participant shall be credited.

(b) A Disabled Participant shall be credited with Years of Credited Service as if he were an Active Participant from his Disability Retirement Date to the date he ceases to be a Disabled Participant as set forth in Subsection 4.4(c).

3.3 Service with Other Employer. A Participant shall be credited with Years of Vesting Service for service with The Five- Twenty Company.

3.4 Loss of Vesting Service. An Employee's Years of Vesting Service shall be cancelled if he incurs a Break in Service at a time when his vested percentage under Section 6.1 is zero or his Accrued Benefit is zero.

3.5 Loss of Credited Service. An Employee's Years of Credited Service shall be cancelled if, upon his Separation from Service, he receives a single-sum payment pursuant to

Subsection 7.8(a), Subsection 7.3(a)(5), or is deemed to receive a single-sum payment pursuant to Subsection 7.8(b).

3.6 Restoration of Service.

(a) The Years of Vesting Service and Years of Credited Service of an Employee whose Years of Vesting Service and Years of Credited Service have been cancelled pursuant to Section 3.4 and/or Section 3.5 shall be restored to his credit if he thereafter completes a Year of Vesting Service at a time when the number of his consecutive Breaks in Service is less than the greater of (a) the number of Years of Vesting Service to his credit when the first such Break in Service occurred, or (b) five. Notwithstanding the foregoing, the Years of Credited Service of a Participant described in Subsection 7.8(a) shall not be restored except as provided in Subsection (b).

(b) If a Participant who receives a single sum distribution under Subsection 7.8(a) or Subsection 7.3(a)(5) that is less than the single-sum value of his entire Accrued Benefit again becomes a Covered Employee, his Years of Credited Service cancelled pursuant to Section 3.5 shall be restored upon his full repayment of the amount of such distribution, plus interest from the date of distribution to the date of repayment at the rate described in section 411(c)(2)(C)(iii)(I) of the Code; provided, however, that such repayment must be made before the earlier of (1) five years after the date the Participant again becomes a Covered Employee, or (2) the first date the Participant incurs five consecutive Breaks in Service following the date of the single-sum distribution.

ARTICLE IV

ELIGIBILITY FOR BENEFITS

4.1 Normal Retirement. A Participant who has a Separation from Service on his Normal Retirement Date shall be entitled to a pension. Such Participant's Benefit Commencement Date shall be his Normal Retirement Date.

4.2 Late Retirement. A Participant who has a Separation from Service after his Normal Retirement Date shall be entitled to a pension. Such Participant's Benefit Commencement Date shall be the earlier of his Late Retirement Date or his Required Beginning Date; provided, however, that upon reaching his Normal Retirement Date, the Participant may elect that his Benefit Commencement Date is his Normal Retirement Date.

4.3 Early Retirement. A Participant who has an Early Retirement Date shall be entitled to a pension. Such Participant's Benefit Commencement Date shall be his Normal Retirement Date; provided, that he may elect as his Benefit Commencement Date his Early Retirement Date or the first day of any month after his Early Retirement Date and not after his Required Beginning Date. Such election must be made no earlier than 90 days prior to the Benefit Commencement Date elected by the Participant.

4.4 Disability Retirement.

(a) A Participant who has a Disability Retirement Date shall continue to be credited with Years of Credited Service as set forth in Article III while he remains a Disabled Participant. Such Participant shall be entitled to a pension. Such Participant's Benefit Commencement Date shall be determined under Section 4.1, 4.2, 4.3 or Article VI, whichever is applicable, determined as if he had a Separation from Service on the date he ceases to be a Disabled Participant under Subsection (c) of this Section.

(b) Total Disability shall be determined by the Committee, which may consult with a medical examiner who shall have the right to make such physical examinations and other investigations as may be reasonably required to determine Total Disability. The Committee may direct that any former Employee who is being credited with Years of Credited Service by reason of Total Disability shall be reexamined without expense to him from time to time prior to the date specified in Subsection (c) of this Section, but not more than twice in any Plan Year, to determine whether his Total Disability continues to exist.

(c) A Disabled Participant shall cease to be such if and when:

(1) he reaches the later of (A) his Normal Retirement Date or (B) the date that is "X" years after his Disability Retirement Date, when "X" is determined under the following table:

Age at Disability Retirement Date	**"X"**
61 or younger	Years to Age 65
62	3-1/2
63	3
64	2-1/2
65	2
66	1-3/4
67	1-1/2

68	1-1/4
69 or older	1

(2) he ceases to suffer from a Total Disability;

(3) he is eligible for and elects to receive payment of Plan benefits under any other provision of the Plan;

(4) he refuses to submit to reexamination in accordance with Subsection (b) of this Section; or

(5) he dies.

When a Disabled Participant ceases to be such, he shall cease to be credited with Years of Credited Service, and he shall be entitled to a pension (or a death benefit) under the other provisions of the Plan, applied as if he had a Separation from Service on the date he ceased to be a Disabled Participant.

4.5 Furnishing Data. Each Employee and beneficiary shall furnish such information as the Committee may consider necessary for the determination of the Employee's rights and benefits under the Plan and shall otherwise cooperate fully with the Committee in the administration of the Plan. Payment of benefits shall be deferred until all of such information is supplied.

ARTICLE V

CALCULATION OF BENEFITS

5.1 Accrued Benefit.

(a) Subject to Subsection (b) of this Section, effective on and after January 1, 1989, a Participant's Accrued Benefit shall be a monthly retirement benefit equal to one-twelfth (1/12th) of thirty-five percent (35%) of his Final Average Compensation multiplied by a fraction, the numerator of which is his Years of Credited Service and the denominator of which is the greater of 25 or the number of Years of Credited Service the Employee will have if he remains employed until he attains age 65.

(b) Notwithstanding Subsection (a) of this Section, effective January 1, 1989, a Participant shall be entitled to receive a minimum benefit calculated in accordance with this Subsection (b) if such benefit exceeds the benefit calculated under Subsection (a) of this Section. Effective solely for Years of Service and Compensation credited for purposes of benefit accrual prior to January 1, 1989, a Participant's minimum normal retirement pension shall be a monthly retirement benefit equal to one-twelfth (1/12th) of:

(1) 40% of the Average Annual Compensation; plus

(2) 37% of that portion of Average Annual Compensation which is in excess of Average Social Security Wage Base; multiplied by

(3) a fraction, the numerator of which is his Years of Credited Service accrued prior to January 1, 1989 and the denominator of which is his Years of Credited Service the Employee will have if he remains employed until he attains age 65; and

(4) if a participant has completed less than fifteen (15) Years of Service at Normal Retirement Age (or would have completed less than fifteen (15) Years of

Service if he had remained in employment until Normal Retirement Age), the Participant's normal retirement pension computation shall be reduced by a factor of one-fifteenth (1/15th) for each Year of Service less than 15 the Participant has completed or would have completed.

Notwithstanding any other provision of the Plan to the contrary, defined terms contained in this Subsection (b) of Section 5.1 shall have the meaning given to such terms in the Plan as it existed prior to the Effective Date.

(c) The Accrued Benefit of any Participant who was a Participant at any time prior to January 1, 1994 and whose Compensation with respect to any Plan Year beginning prior to January 1, 1994 exceeded $150,000, shall be the greater of (1) or (2), where:

(1) is the Participant's Accrued Benefit calculated on the basis of all of his Years of Credited Service and his Final Average Compensation, limiting the Participant's Compensation for Plan Years beginning prior to January 1, 1994 to $150,000 and for Plan Years beginning on or after January 1, 1994 to $150,000 or such other amount as in effect under Code section 401(a)(17) for such Plan Year; and

(2) is the sum of (A) plus (B), where:

(A) is the greater of (i) or (ii), where:

(i) is the sum of (I) plus (II), where:

(I) is the Participant's Accrued Benefit calculated on the basis of his Years of Credited Service and Final Average Compensation as of December 31, 1988, not limiting his Final Average Compensation under Code section 401(a)(17), and

(II) is the Participant's Accrued Benefit calculated on the basis of his Years of Credited Service between December 31, 1988 and

December 31, 1993, and his Final Average Compensation as of December 31, 1993, limiting his Compensation for all Plan Years to $235,840, and

(ii) is the Participant's Accrued Benefit calculated on the basis of his Years of Credited Service and Final Average Compensation as of December 31, 1993, limiting his Compensation for all Plan Years to $235,840, and

(B) is the Participant's Accrued Benefit calculated on the basis of his Years of Credited Service after December 31, 1993 and his Final Average Compensation, limiting his Compensation for all Plan Years to $150,000 or such other amount as is in effect under Code section 401(a)(17) for Plan Years beginning on or after January 1, 1994.

5.2 Normal Retirement. A Participant who is entitled to a pension under Section 4.1 shall receive an annual pension, payable monthly. Subject to Section 5.10, such pension shall be the Actuarial Equivalent, in the form set forth in Article VII, of the Participant's Accrued Benefit as of his Normal Retirement Date.

5.3 Late Retirement. A Participant who is entitled to a pension under Section 4.2 shall receive an annual pension, payable monthly. Subject to Section 5.10, such pension shall be the Actuarial Equivalent, in the form set forth in Article VII, of the Participant's Accrued Benefit calculated as follows:

(a) If the Participant elects to commence benefits on his Normal Retirement Date, his Accrued Benefit shall be calculated as of his Normal Retirement Date. The amount of the pension payable to the Participant shall be adjusted annually as of January 1 in each calendar year following his Benefit Commencement Date, up to and including the January 1 following his Separation from Service. Such annual adjustment shall include any increase (but not any decrease) in the Participant's Accrued Benefit, determined in accordance with

Section 5.1, as a result of additional Years of Credited Service and Compensation since the Participant's Benefit Commencement Date or the last such annual adjustment, whichever applies. In addition, such annual adjustment shall be reduced (but not below zero) by the Actuarial Equivalent of any benefits paid to the Participant since his Benefit Commencement Date, to the extent not previously taken into account under this Subsection (a).

(b) If the Participant elects to defer his Benefit Commencement Date beyond his Normal Retirement Date:

(1) The Participant's Accrued Benefit shall be calculated as of the end of the Plan Year in which occurs the Participant's Normal Retirement Date, as an amount equal to the greater of :

(A) his Accrued Benefit as of his Normal Retirement Date, increased on an Actuarially Equivalent basis to reflect deferral of the Participant's Benefit Commencement Date for one year, or

(B) his Accrued Benefit calculated as under Section 5.1 based on Years of Credited Service and Compensation through the end of the such Plan Year.

(2) The Participant's Accrued Benefit shall be calculated thereafter as of the end of each subsequent Plan Year, as an amount equal to the greater of:

(A) his Accrued Benefit as of the last day of the preceding Plan Year, increased on an Actuarially Equivalent basis to reflect deferral of the Participant's Benefit Commencement Date for one year, or

(B) his Accrued Benefit calculated as under Section 5.1 based on Years of Credited Service and Compensation through the end of such Plan Year.

(3) If a Participant's Required Beginning Date, and therefore his Benefit Commencement Date, precedes his Late Retirement Date, the amount of the pension payable to the Participant shall be determined as of his Benefit Commencement Date and shall be adjusted annually as of January 1 in each calendar year following his Benefit Commencement Date, up to and including the January 1 next following his Late Retirement Date. Such annual adjustment shall include any increase (but not any decrease) in the Participant's Accrued Benefit, determined in accordance with Section 5.1, as a result of additional Years of Credited Service and Compensation since the Participant's Benefit Commencement Date or the last such annual adjustment, whichever applies.

5.4 Early Retirement. A Participant who is entitled to a pension under Section 4.3 shall receive an annual pension, payable monthly. Subject to Section 5.10, such pension shall be the Actuarial Equivalent, in the form set forth in Article VII, of the Participant's Accrued Benefit as of his Early Retirement Date, reduced by 1/15 for each year from age 60 to his Normal Retirement Date and by 1/30 for each year from age 55 to age 60 by which his Benefit Commencement Date precedes his Normal Retirement Date.

5.5 Disability Retirement.

(a) Subject to Section 5.10, a Participant who is entitled to a pension under Section 4.4 shall receive the benefit provided under Section 5.2, 5.3, 5.4 or Article VI, whichever applies. In addition, such annual adjustment shall be reduced (but not below zero) by the Actuarial Equivalent of any benefits paid to the Participant since his Benefit Commencement Date, to the extent not previously taken into account under this Subsection.

(b) For the purposes of this Section, a Participant's Final Average Compensation shall be computed on the assumption that his Compensation for each Plan Year

that ends after his Disability Retirement Date is equal to his Compensation for the last Plan Year ended on or before his Disability Retirement Date.

5.6 Prohibition Against Decrease in Benefits Payable. A Participant's Accrued Benefit as of his Normal Retirement Date shall not be less than his pension, in the form of an immediate single life annuity, would have been if he had had a Separation from Service on any earlier date.

5.7 Death Before Separation from Service.

(a) Effective January 1, 1994, upon the death of a Participant who is then an Employee or, effective January 1, 2007, who at the time of death was performing qualified military service as defined in section 414(u) of the Code, the Participant's designated beneficiary shall be paid a death benefit equal to the Actuarial Equivalent of the Participant's fully vested Accrued Benefit as of the date of his death.

(b) The death benefit determined in accordance with Subsection (a) of this Section shall be payable to the Participant's designated beneficiary within 60 days following the end of the Plan Year in which the Participant's death occurs. This benefit shall not apply to a Participant with respect to whom the survivor's benefit under Section 5.8 is payable and has not been properly waived.

5.8 Survivor's Benefit for Surviving Spouse.

(a) Subject to Subsection (b) of this Section, if a Participant who has any vested interest in his Accrued Benefit under the Plan, dies before his Benefit Commencement Date and has a Surviving Spouse, such Surviving Spouse shall receive a survivor's benefit. Such benefit shall be a monthly pension for life and shall begin, as elected in writing by the Surviving Spouse not more than 180 days prior to the Benefit Commencement

Date, on the first day of any month following the earliest date on which the Participant could have elected to receive immediate retirement benefits, but not later than the date that would have been the Participant's Normal Retirement Date. If the Participant dies after his Normal Retirement Date, benefits shall commence on the first day of the month following the month of the Participant's death. Subject to Section 5.10, the survivor's benefit shall be the benefit such Surviving Spouse would have received if the Participant (1) had had a Separation from Service on the date of his death (if he is then an Employee), (2) had survived to the Benefit Commencement Date elected by the Surviving Spouse, (3) had then begun to receive an immediate retirement benefit in the normal form under Subsection 7.2(b), and (4) died on the following day.

(b) The survivor's benefit under this Section shall not be payable and the death benefit under Section 5.7 shall be payable instead with respect to a Participant who elects in accordance with the following rules to waive the survivor's benefit under this Section and to have the death benefit under Section 5.7 be payable instead. Such election may be made at any time during the period that begins (i) on the first day of the Plan Year in which the Participant attains Age 35, or (ii) on the date of his Separation from Service, in the case of a Participant who has a Separation from Service prior to Age 35, with respect to benefits accrued prior to such separation, and ends on the date of the Participant's death; provided that such election shall be effective only if:

(1) (A) the Participant's Spouse (or the Spouse's legal guardian if the Spouse is legally incompetent) executes a written instrument whereby such Spouse either:

(i) consents to such election, but only insofar as such election waives the survivor's benefit under this Section and, if applicable, names a specific beneficiary or beneficiaries to receive the death benefit under Section 5.7; or

(ii) consents to such election and consents prospectively to any subsequent designation of someone other than the Spouse to receive all or part of the death benefit under Section 5.7 (provided such instrument acknowledges the Spouse's right to limit consent to a specific beneficiary); and

(B) such instrument acknowledges the effect of the election to which the Spouse's consent is being given and is witnessed by a Plan representative or a notary public; or

(2) the Participant establishes to the satisfaction of the Committee that his Spouse cannot be located or furnishes a court order to the Committee establishing that the Participant is legally separated or has been abandoned (within the meaning of local law), unless a qualified domestic relations order pertaining to such Participant provides that the Spouse's consent must be obtained.

The consent of a Spouse in accordance with this Subsection (b) shall not be effective with respect to other Spouses of the Participant, and an election to which Paragraph (b)(2) of this Section applies shall become void if the circumstances causing the consent of the Spouse not to be required cease to exist prior to the Participant's Benefit Commencement Date.

(c) A Participant may revoke his election to waive the survivor's benefit. Such revocation may be made at any time prior to the Participant's death.

(d) The Committee shall provide to each Participant a written explanation of:

(1) the terms and conditions of the survivor's benefit under this Section and the death benefit under Section 5.7;

(2) the Participant's right to waive the survivor's benefit and the effect of such waiver;

(3) the rights of the Participant's Spouse with respect to such waiver; and

(4) the Participant's right to revoke a waiver of the survivor's benefit and the effect of such revocation.

The written explanation described in this Subsection shall be provided once during either (A) the three-year period that begins on the first day of the Plan Year in which the Participant attains Age 32, or (B) the one-year period that begins on the day he becomes a Participant. With regard to a Participant who has a Separation from Service before attaining Age 35, such written notice shall be provided no earlier than one year before, and no later than one year after, the Participant's Separation from Service.

5.9 Death Benefit After Retirement. If a Participant dies after his Benefit Commencement Date, his beneficiary shall be entitled to receive any amount payable under the form of benefit that is in effect for such Participant.

5.10 Maximum Benefit. The provisions of this Section 5.10 shall be effective for Limitation Years beginning on or after July 1, 2007 and shall be construed to comply with section 415 of the Code and the regulations thereunder. The application of the provisions of this Section 5.10 shall not cause the maximum annual benefit payable to any Participant to be less than the Participant's accrued benefit under this and any other qualified defined benefit plan of a Participating Company or a 50% Affiliated Company as of the end of the last Limitation Year

beginning before July 1, 2007 under provisions of the plans that were both adopted and in effect before April 5, 2007. The aggregation of defined benefit plans for purposes of this Section 5.10 shall be determined in accordance with the rules set forth in Section 415(f) of the Code and the regulations issued thereunder.

(a) (1) Notwithstanding anything in this Article to the contrary, in no event shall the combined annual benefit payable with respect to a Participant on a single life basis, under this and any other qualified defined benefit plan to which a Participating Company or a 50% Affiliated Company contributes, exceed the lesser of (A) $185,000 (as adjusted under section 415(d) of the Code) or (B) one hundred percent (100%) of the Participant's average Compensation during the three consecutive calendar years in which such Compensation is the highest, regardless of whether he was a Participant during such years. For a Participant who is employed by a Participating Company for less than three consecutive years, the period of the Participant's high-three years of service is the actual number of consecutive years of service (including fractions of years, but not less than one year). In the case of a Participant who has had a Separation from Service, and who is subsequently rehired by a Participating Company, the period of the Participant's high-three years of service is calculated by excluding any years for which the Participant performs no services for and receives no Compensation from the Participating Company (the break period), and by treating the year of service immediately prior to and the year of service immediately after the break period as if the years were consecutive.

(2) (A) If the benefit is payable with respect to a Participant who has been an Active Participant for fewer than 10 full years at the time that retirement benefits begin, the dollar limitation described in Subparagraph (a)(1)(A) of this Section shall be

multiplied by a fraction, the numerator of which is the number of the Participant's years as an Active Participant and the denominator of which is 10.

(B) If the benefit is payable with respect to a Participant who has fewer than 10 Years of Vesting Service, the limitations described in Subparagraph (a)(1)(B), Paragraph (a)(4) and Paragraph (a)(5) of this Section shall be multiplied by a fraction, the numerator of which is the number of the Participant's Years of Vesting Service and the denominator of which is 10.

(3) (A) If the Participant's Benefit Commencement Date occurs before the Participant attains Age 62, the dollar limitation in subparagraph (a)(1)(A) applicable to the Participant at the earlier Age is an annual benefit payable in the form of a straight life annuity beginning at the earlier Age that is the Actuarial Equivalent of the defined benefit dollar limitation applicable to the Participant at Age 62 (adjusted under Paragraph (2) above, if required). Adjustments under this Subparagraph (3)(A) shall be made in accordance with section 1.415(b)-1(d) of the Treasury Regulations.

(B) If the Participant's Benefit Commencement Date occurs after the Participant attains Age 65, the defined benefit dollar limitation applicable to the Participant at the later Age is the annual benefit payable in the form of a straight life annuity beginning at the later Age that is the Actuarial Equivalent of the defined benefit dollar limitation applicable to the Participant at Age 65 (adjusted under Paragraph (2) above, if required). Adjustments under this Subparagraph (3)(B) shall be made in accordance with section 1.415(b)-1(e) of the Treasury Regulations.

(4) Except as provided in Subparagraph (C) below, an annual benefit payable in a form other than a straight life annuity must be adjusted to an Actuarially Equivalent straight life annuity before applying the limitations of this Section.

(A) If the Participant's benefit is paid in a form that is not subject to section 417(e)(3) of the Code, the Actuarially Equivalent straight life annuity is the greater of (i) the annual amount of the straight life annuity (if any) payable to the Participant commencing at the same Benefit Commencement Date as the form of benefit payable to the Participant; or (ii) the annual amount of the straight life annuity commencing at the same Benefit Commencement Date that has the same actuarial present value as the form of benefit payable to the Participant, computed using a 5% interest rate and the Section 417 Mortality Table.

(B) If the Participant's benefit is paid in a form that is subject to section 417(e)(3) of the Code, the Actuarially Equivalent straight life annuity is the greatest of the annual amount of the straight life annuity commencing at the Benefit Commencement Date that has the same actuarial present value as the form of benefit payable computed using (i) the interest rate and mortality table specified in the Plan for Actuarial Equivalence, (ii) a 5.5% interest assumption and the Section 417 Mortality Table, or (iii) the Section 417 Interest Rate and the Section 417 Mortality Table, divided by 1.05. However, for a distribution with a Benefit Commencement Date occurring in Plan Years beginning in 2004 or 2005, the Actuarially Equivalent straight life annuity is the greater of the annual amount of the straight life annuity that has the same actuarial present value as the form of benefit payable using (i) the interest rate and mortality table specified in the Plan for Actuarial Equivalence, or (ii) a 5.5% interest assumption and the Section 417 Mortality Table.

(C) No actuarial adjustment to the annual benefit is required for (i) survivor benefits payable to a surviving spouse under a qualified joint and survivor annuity to the extent that such benefits would not be payable if the Participant's benefit were not paid in the form of a qualified joint and survivor annuity, (ii) ancillary benefits that are not directly related to retirement benefits, and (iii) the inclusion in the form of benefit of an automatic benefit increase, as described in section 1.415(b)-1(c)(5) of the Treasury Regulations.

(5) The annual benefit payable with respect to a Participant shall be deemed not to exceed the limits set forth in Subsection (a) if (A) the annual benefit does not exceed $10,000 (as adjusted as set forth in Paragraph (a)(2)) for the current Plan Year or for any prior Plan Year, and (B) the Participant has at no time participated in a defined contribution plan maintained by a Participating Company or a 50% Affiliated Company.

5.11 <u>Funding Based Benefit Limitations</u>. The following rules set forth the limitations on benefits imposed as a result of the funding status of the Plan for a given Plan Year. The provisions of this Section 5.11 shall be interpreted to comply with the requirements of Section 436 of the Code and the regulations issued thereunder.

(a) No amendment to the Plan which has the effect of increasing liabilities of the Plan by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accrual, or changing the rate at which benefits become nonforfeitable may take effect during any Plan Year if the Plan's actuary determines (or is presumed to have determined) that the adjusted funding target percentage of the Plan for such Plan Year is less than 80%, or would be less than 80% taking into account such amendment. This Section 5.11(b) shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year (or if later, the

effective date of the amendment) upon payment by the Company of a contribution equal to the amount required under Section 436(c)(2) of the Code.

(b) In the event that the Plan's actuary determines (or is presumed to have determined) that the adjusted funding target attainment percentage of the Plan is less than 60% for the Plan Year, the following limits shall apply:

(1) A Participant or beneficiary is not permitted to elect an optional form of benefit that includes a prohibited payment, and the Plan will not pay any prohibited payment, with an annuity starting date on or after the applicable Section 436 measurement date.

(2) Benefit accruals shall cease as of the applicable Section 436 measurement date. This Section 5.11(b)(2) shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company of a contribution equal to the amount sufficient to result in an adjusted funding target attainment percentage of 60%.

(c) A Participant or beneficiary is not permitted to elect an optional form of benefit that includes a prohibited payment, and the Plan will not pay any prohibited payment, with an annuity starting date that occurs during any period in which the Company is a debtor in a bankruptcy proceeding, except for payments made within a Plan Year with an annuity starting date that occurs on or after the date on which the Plan's actuary certifies that the Plan's adjusted funding target attainment percentage for that Plan Year is not less than 100%.

(d) In the event that the Plan's actuary determines (or is presumed to have determined) that the adjusted funding target attainment percentage of the Plan for the Plan Year is 60% or greater, but less than 80%, a Participant or beneficiary is not permitted to elect

the payment of an optional form of benefit that includes a prohibited payment, and the Plan will not pay any prohibited payment, with an annuity starting date on or after the applicable Section 436 measurement date unless the present value of the portion of the benefit that is being paid in a prohibited payment does not exceed the lesser of :

(1) 50% of the present value of the benefit payable in the optional form of benefit that includes the prohibited payment, or

(2) 100% of the present value of the maximum guaranteed benefit published by the Pension Benefit Guaranty Corporation with respect to a Participant for the year in which the annuity starting date occurs.

In the case of a Participant with respect to whom a prohibited payment (or a series of prohibited payments under a single optional form of benefit) is made pursuant to this Section 5.11.(d), no additional prohibited payment may be made with respect to the Participant during any period of consecutive Plan Years for which prohibited payments are limited under Sections 5.11(b), 5.11(c), or 5.11(d).

(e) If an optional form of benefit that is otherwise available under the Plan is not available as of the annuity starting date because of the restrictions of Section 5.11(d), then the Participant or beneficiary may elect to:

(1) Receive the unrestricted portion of the optional form of benefit at the annuity starting date,

(2) Commence benefits in any other optional form of benefit available under the Plan at the same annuity starting date, or

(3) Defer commencement of benefits to the extent permitted under the Plan.

If the Participant or beneficiary elects payment of the unrestricted portion of the benefit as described in (1) above, then the Participant or beneficiary may elect payment of the remainder of his benefit in any optional form of benefit at that annuity starting date otherwise available under the Plan that would not have included a prohibited payment if that optional form of benefit applied to the entire benefit.

(f) In the event that a benefit limitation under Section 5.11(a), 5.11(b), 5.11(c), or 5.11(d) applies for a Plan Year, the adjusted funding target attainment percentage for such Plan Year shall continue to apply for subsequent Plan Years until certification by the Plan's actuary that the adjusted funding target attainment percentage for the Plan Year is at a level at which such limits no longer apply. In the event the Plan's actuary does not provide certification of the adjusted funding target attainment percentage by the end of the ninth month of any Plan Year, the Plan shall be presumed to have an adjusted funding target attainment percentage for the Plan Year of less than 60% as of the first day of such Plan Year.

(g) The following terms shall apply for purposes of this Section 5.11:

(1) "Adjusted funding target attainment percentage" means such term as is defined in Section 436(j)(2) of the Code and Treas. Reg. § 1.436-1(j)(1).

(2) "Annuity starting date" means such term as is defined in Treas. Reg. § 1.436-1(j)(2).

(3) "Prohibited payment" means (A) any payment in excess of the monthly amount paid under a single life annuity to a Participant or beneficiary whose annuity starting date occurs during a period in which the benefit limitations set forth in this Section 5.11 are in effect, (B) any payment for the purchase of an irrevocable commitment from an insurer to pay benefits, (C) any transfer of assets and liabilities to any other plan maintained by the

Company or an Affiliate that is made in order to avoid or terminate the application of the limitations of this Section 5.11, and (D) any other payment specified by the Secretary of the Treasury under Section 436 of the Code. Such term shall not include the payment of a benefit which under Section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

(4) "Section 436 measurement date" means such term as is defined in Treas. Reg. § 1.436-1(j)(8).

ARTICLE VI

VESTING

6.1 Nonforfeitable Amounts.

(a) A Participant who is credited with one or more Hours of Service as an Employee on or after January 1, 1989 shall have a nonforfeitable interest in his Accrued Benefit determined in accordance with the following schedule:

Years of Vesting Service	Nonforfeitable Interest
Less than two years	0 percent
two years	20 percent
three years	40 percent
four years	60 percent
five years	80 percent
six years	100 percent

(b) Notwithstanding the foregoing, a Participant who is an Employee shall have a 100% nonforfeitable interest in his Accrued benefit upon: (1) the date on which he attains Age 65; (2) the date of his death; or (3) the date he suffers a Total Disability.

6.2 Treatment of Terminated Vested Participant.

(a) A Participant who has a Separation from Service at a time when he has a nonforfeitable interest in his Accrued Benefit pursuant to Section 6.1, other than by death or as provided in Article IV, shall be entitled to a pension. His Benefit Commencement Date shall be his Normal Retirement Date; provided, that he may elect as his Benefit Commencement Date the first day of any month after his Separation from Service and not after his Required Beginning Date. Such election must be made no earlier than 90 days prior to the Benefit Commencement Date elected by the Participant. Subject to Section 5.10, the pension payable under this Section shall be equal to the Participant's Accrued Benefit as of the date of his

Separation from Service, multiplied by his nonforfeitable interest under Section 6.1. The Participant shall forfeit any remainder.

(b) If a Participant who is eligible for a deferred pension under Subsection (a) of this Section has 10 or more Years of Credited Service to his credit as of the date of his Separation from Service, he may elect as his Benefit Commencement Date (1) the first day of the calendar month coincident with or next following his 55th birthday, or (2) the first day of any month after such birthday and before his Required Beginning Date. Such election must be made no earlier than 90 days prior to the Benefit Commencement Date elected by the Participant.

(c) A Participant who elects a Benefit Commencement Date under Subsection (b) of this Section shall receive the benefit described in Subsection (a) of this Section in an amount reduced under Section 5.4.

(d) Notwithstanding any other provision in the Plan, an increase in the Social Security taxable wage base or benefit level shall not reduce the value of the nonforfeitable benefit payable to a Participant who has had a Separation from Service with respect to service prior to his Separation from Service, regardless of whether the Participant returns to employment as a Covered Employee.

6.3 Form and Payment of Benefit. Terminated vested benefits shall be paid in a form provided for in Article VII.

6.4 Termination of Benefit. The last vested benefit payment hereunder shall be made in accordance with the provisions of Article VII.

6.5 Special Rules for Certain Terminated Participants.

(a) Notwithstanding Section 2.1, if a Participant:

(1) is eligible for a deferred vested benefit under the Plan,

(2) has been credited with at least one Hour of Service on or after September 2, 1974,

(3) had a Separation from Service prior to the first day of the first Plan Year beginning after December 31, 1975,

(4) has not thereafter been an Employee, and

(5) is alive on August 23, 1984 and has not begun to receive benefit payments as of that date, such Participant's retirement benefits shall be paid in accordance with Article VII.

(b) Notwithstanding Section 2.1, if a Participant:

(1) has at least one Hour of Service after the first day of the Plan Year beginning on or immediately after January 1, 1976,

(2) has not been credited with any Hours of Service after August 22, 1984,

(3) has at least 10 Years of Vesting Service and a vested right to all or a portion of his Accrued Benefit, and

(c) is alive on August 23, 1984 and has not begun to receive benefit payments as of that date, he may elect to be covered by the survivor's benefit described in Section 5.8.

ARTICLE VII

PAYMENT OF BENEFITS

7.1 Minimum Distribution Requirements.

(a) Except as required by Subsection (c) of this Section, a Participant's Benefit Commencement Date shall be no earlier than the date of his Separation from Service.

(b) Except as required by Subsection (c) of this Section, unless a Participant elects otherwise, his Benefit Commencement Date shall be no later than the 60th day after the close of the Plan Year in which the Participant attains Age 65 or has a Separation from Service, whichever occurs last.

(c) A Participant's Benefit Commencement Date shall be no later than his Required Beginning Date.

(d) Notwithstanding anything in the Plan to the contrary, if a Participant dies before his Benefit Commencement Date, his entire interest under the Plan, to the extent not forfeited, shall be distributed either:

(1) not later than December 31 of the calendar year containing the fifth anniversary of the date of the Participant's death, or

(2) over the life or life expectancy of the Participant's beneficiary, commencing no later than (A) December 31 of the calendar year following the year of the Participant's death, or (B) if the beneficiary is the Participant's Spouse, December 31 of the later of (i) the calendar year following the year of the Participant's death or (ii) the calendar year in which the Participant would have attained Age 70½.

(e) Notwithstanding anything in the Plan to the contrary, the form and the timing of all distributions under the Plan shall be such that the amount of any distribution

shall not be less than required under regulations issued by the Department of the Treasury under section 401(a)(9) of the Code, including the incidental death benefit requirements of section 401(a)(9)(G) of the Code.

(f) This Section shall apply to all Participants, including Participants who had a Separation from Service or ceased to be a Covered Employee prior to January 1, 1997.

7.2 Normal Form of Benefit.

(a) Benefits under the Plan shall be paid in the normal form of benefit described in Subsection (b) or (c), as the case may be, unless the Participant elects an optional form of benefit under Section 7.3. No spousal consent shall be required for payment of benefits in the normal form.

(b) The normal form of benefit for a Participant who has a Spouse as of his Benefit Commencement Date shall be a joint and survivor annuity, with monthly installments payable after the death of the retired Participant to his Surviving Spouse, if he leaves one, for the life of such Surviving Spouse in an amount equal to fifty percent (50%) of the benefit paid to the retired Participant.

(c) The normal form of benefit for a Participant who does not have a Spouse as of his Benefit Commencement Date shall be a single life annuity with equal monthly installments payable to the retired Participant for his lifetime.

7.3 Optional Form of Benefit.

(a) In lieu of the normal form of benefit as determined under Section 7.2, the Participant may elect, subject to the rules of Section 7.4, one of the following optional

forms of benefit, each of which shall be the Actuarial Equivalent of the normal form of benefit under Section 7.2:

(1) a single life annuity with equal monthly installments payable to the retired Participant for his lifetime; or

(2) a joint and survivor annuity with any individual designated beneficiary, payable in monthly installments to the Participant for his lifetime and with fifty percent (50%) of the amount of such monthly installment payable after the death of the Participant to the designated beneficiary of such Participant, if then living, for the life of such designated beneficiary. Notwithstanding the foregoing, the percentage payable to the Participant's beneficiary (unless the beneficiary is the Participant's Spouse) after the Participant's death may not exceed the applicable percentage from Table I in Schedule A; or

(3) a joint and survivor annuity with any individual designated beneficiary, payable in monthly installments to the Participant for his lifetime and with seventy-five percent (75%) of the amount of such monthly installment payable after the death of the Participant to the designated beneficiary of such Participant, if then living, for the life of such designated beneficiary. Notwithstanding the foregoing, the percentage payable to the Participant's beneficiary (unless the beneficiary is the Participant's Spouse) after the Participant's death may not exceed the applicable percentage from Table I in Schedule A; or

(4) a joint and survivor annuity with any individual designated beneficiary, payable in monthly installments to the Participant for his lifetime and with one hundred percent (100%) of the amount of such monthly installment payable after the death of the Participant to the designated beneficiary of such Participant, if then living, for the life of such designated beneficiary. Notwithstanding the foregoing, the percentage payable to the

Participant's beneficiary (unless the beneficiary is the Participant's Spouse) after the Participant's death may not exceed the applicable percentage from Table I in Schedule A; or

(5) subject to Section 10.3, a single sum payment in lieu of any other benefits under the Plan in complete discharge of all obligations to the Participant under the Plan payable as soon as is practical following termination of the Participant's active participation in the Plan; or

(6) a joint and survivor annuity, with the Participant's Spouse, paid as soon as is practical in monthly installments to the Participant for his lifetime and with fifty percent (50%) of the amount of such monthly installment payable after the death of the Participant to the Surviving Spouse of such Participant, if then living, for the life of such Surviving Spouse; or

(7) if the Participant does not have a Spouse as of his Benefit Commencement Date, a single life annuity paid as soon as practical in equal monthly installments to the Participant for his lifetime; or

(8) subject to Section 10.3, substantially equal periodic installment payments made to the Participant or his designated beneficiary; or

(9) a single life annuity payable in equal monthly installments to the retired Participant for his lifetime, with 120 monthly payments guaranteed. If the Participant dies before he has received 120 monthly payments, then beginning on the first day of the month in which the Participant's death occurs and continuing until the balance of the guaranteed payments have been made, payments in the amount payable to the Participant shall be made to the Participant's beneficiary. If the Participant's beneficiary dies before the full number of guaranteed monthly payments have been made, the Actuarial Equivalent of any

balance of guaranteed payments shall be paid in a single sum to the estate of the last to survive of the Participant or the beneficiary. Notwithstanding the foregoing, the number of monthly payments guaranteed shall be calculated so that the number of guaranteed monthly payments remaining as of the beginning of the calendar year preceding the Participant's Required Beginning Date does not exceed the joint life expectancy of the Participant and his beneficiary, or if less, and the Participant's beneficiary is not the Participant's Spouse, the applicable number from Table II in Schedule A multiplied by 12; or

(10) a joint and survivor annuity, with the Participant's Spouse, paid as soon as is practical in monthly installments to the Participant for his lifetime and with seventy-five percent (75%) of the amount of such monthly installment payable after the death of the Participant to the Surviving Spouse of such Participant, if then living, for the life of such Surviving Spouse.

7.4 <u>Rules for Election of Optional Form of Benefit</u> A Participant may elect an optional form of benefit under Section 7.3 by filing a written notice with the Committee in the form and manner prescribed by the Committee and in no other. The following rules shall be applied in a uniform and nondiscriminatory manner with respect to the election of optional forms of benefit.

(a) A Participant may elect an optional form of benefit at any time not earlier than 180 days prior to his Benefit Commencement Date.

(b) A Participant who does not establish to the satisfaction of the Committee that he has no Spouse on his Benefit Commencement Date may elect to receive an optional form of benefit under Section 7.3 only if:

(1) (A) his Spouse (or the Spouse's legal guardian if the Spouse is legally incompetent) executes a written instrument whereby such Spouse:

(i) consents not to receive the normal form of benefit described in Subsection (b) of Section 7.2;

(ii) consents to the specific optional form elected by the Participant, or (provided such instrument acknowledges the Spouse's right to limit consent to a specific optional form) to the Participant's right to choose any optional form without any further consent by the Spouse; and

(iii) if applicable, consents in writing to either the specific beneficiary or beneficiaries designated by the Participant pursuant to his election or (provided such instrument acknowledges the Spouse's right to limit consent to a specific beneficiary) to the Participant's right to designate any beneficiary or beneficiaries without any further consent by the Spouse; and

(B) such instrument acknowledges the effect of the election to which the Spouse's consent is being given and is witnessed by a Plan representative or a notary public; or

(2) the Participant (A) establishes to the satisfaction of the Committee that his Spouse cannot be located or (B) furnishes a court order to the Committee establishing that the Participant is legally separated or has been abandoned (within the meaning of local law), unless a qualified domestic relations order pertaining to such Participant provides that the Spouse's consent must be obtained , or (C) asserts that he is a Participant described in Section 6.5(a).

The consent of a Spouse in accordance with this Subsection (b) shall not be effective with respect to other Spouses of the Participant, and an election to which Paragraph (3) of this Subsection applies shall become void if the circumstances causing the consent of the Spouse not to be required cease to exist prior to the Participant's Benefit Commencement Date.

(c) A Participant may revoke an election under Subsection (b) of this Section. Such revocation may be made at any time prior to the later of (1) his Benefit Commencement Date, or (2) the expiration of the seven-day period that begins the day after the Participant receives the Plan's explanation described in Section 7.5. Such revocation shall not void any prospectively effective consent given by his Spouse in connection with the revoked election.

(d) If a Participant's Spouse or other designated beneficiary dies before the Participant's Benefit Commencement Date, but after an election of a joint and survivor annuity has been made hereunder, the election shall be automatically revoked.

(e) In the event of the divorce of a Participant prior to his Benefit Commencement Date, but following the Participant's election of a form of benefit, the election shall remain in effect unless the election is revoked by the Participant, the Participant remarries, or a qualified domestic relations order provides otherwise.

7.5 Explanations to Participants.

(a) (1) The Committee shall provide to each Participant whose vested Accrued Benefit has an Actuarial Equivalent single-sum value in excess of $5,000 a written explanation of:

(A) the terms and conditions of the normal form of benefit and each optional form of benefit, including information explaining the relative values of each form of benefit;

(B) the Participant's right to waive the normal form of benefit and the effect of such waiver;

(C) the rights of the Participant's Spouse with respect to such waiver;

(D) the right to revoke an election to receive an optional form of benefit and the effect of such revocation; and

(E) if the Participant has not attained Age 65, the Participant's right to defer commencement of his benefit until his Normal Retirement Date and the consequences of a failure to so defer.

(2) Such explanation shall be provided:

(A) no more than 180 days before the Participant's Benefit Commencement Date; and

(B) no less than 30 days before the first distribution to the Participant is actually made, unless

(i) the Participant has been provided with information that indicates that he has at least 30 days to consider his election, and the Participant elects to waive such 30-day consideration period before a distribution of benefits begins;

(ii) the Participant's spouse has consented to the chosen mode of payment, if required under Subsection 7.4(b);

(iii) the Participant is permitted to revoke any affirmative distribution election at least until the expiration of the seven-day period beginning on the day after the explanation was provided; and

(iv) the distribution commences more than seven days after the explanation is provided.

7.6 Termination of Benefits. The last benefit payment hereunder with respect to any Participant shall be:

(a) in the case of a single life annuity, the payment due on the first day of the month in which occurs the death of the retired Participant;

(b) in the case of a surviving Spouse's benefit or a joint and survivor benefit, the payment due on the first day of the month in which occurs the later of the death of the Participant or the death of the Spouse (or, if applicable, the death of the designated beneficiary of such Participant); or

(c) in the case of a single sum payment, such benefit payment.

(d) in the case of an installment payment, the last installment payment due to the Participant or his designated beneficiary.

(e) in the case of the single life annuity with 120 monthly payments guaranteed, the later of the payment due on the first day of the month in which the death of the Participant occurs or the 120th monthly payment.

7.7 Beneficiary Designation.

(a) Except as provided in Subsection 7.4(a), in the case of a Participant whose election period extends beyond his Benefit Commencement Date, a

Participant's designation of a beneficiary under a joint and survivor annuity may not be changed on or after the Participant's Benefit Commencement Date.

(b) A Participant's designation of a beneficiary to receive any remainder of a guaranteed number of payments may be made or changed until the earlier of the Participant's death or the expiration of the guaranteed period.

(c) Subject to the provisions of Subsections (a) and (b) and to the provisions set forth above relating to the rights of Spouses to survivor benefit payments, each Participant may designate or change the previous designation of the beneficiary or beneficiaries who shall receive benefits, if any, after his death. Such designation or change of designation shall be made by executing and filing with the Committee a form prescribed by the Committee and in no other manner. No designation, revocation, or change of beneficiaries shall be valid and effective unless and until filed with the Committee.

7.8 Small Benefit Payments.

(a) Notwithstanding any other provision of the Plan, if the Actuarially Equivalent single-sum value of (1) a Participant's vested Accrued Benefit or (2), if the Participant has died, the Surviving Spouse's benefit under Section 5.7 or 5.8, as applicable, does not exceed $5,000, such benefit shall be paid in a single sum as soon as is practicable after the Participant's Separation from Service, or death, if applicable. In no event shall a distribution be made under this subsection (a) if there are remaining payments to be made with respect to a particular distribution option that has commenced.

(b) If the value of the benefit described in Subsection (a) of this Section is zero, the Participant shall be deemed to have received a single-sum distribution under this Section of his entire vested Accrued Benefit as of the date of his Separation from Service.

7.9 Direct Rollovers of Single Sum Distributions.

(a) If (1) a Participant (including a Participant who had a Separation from Service prior to the Effective Date) entitled to receive a distribution under Section 7.8 or Subsection 7.3(a)(5); (2) a spouse or former spouse of a Participant who is entitled to receive a single sum distribution from the Plan pursuant to a qualified domestic relations order; or (3) a Participant's surviving spouse who is entitled to receive a distribution from the Plan upon the Participant's death, directs the Committee to have the Trustee transfer all or a portion (not less than $500) of the amount to be distributed directly to:

(A) an individual retirement account described in section 408(a) of the Code,

(B) an individual retirement annuity described in section 408(b) of the Code (other than an endowment contract),

(C) a qualified defined contribution retirement plan described in section 401(a) of the Code the terms of which permit the acceptance of rollover contributions, or

(D) an annuity plan described in section 403(a) of the Code.

(E) an annuity contract described in section 403(b) of the Code,

(F) an eligible plan under section 457(b) of the Code that is maintained by a state, a political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state that agrees to separately account for amounts transferred into such plan from this Plan, or

(G) a Roth IRA described in section 408(A) of the Code, all or a portion (not less than $500) of the amount to be distributed shall be so transferred.

(b) A Participant's non-spouse beneficiary who is entitled to receive a distribution from the Plan upon the Participant's death may direct the Committee to have the Trustee transfer all or a portion (not less than $500) of the amount to be distributed directly to an individual retirement account described in section 408(a) of the Code or an individual retirement annuity described in section 408(b) of the Code that is established on behalf of the designated beneficiary and that will be treated as an inherited IRA pursuant to section 402(c)(11) of the Code.

(c) The Participant, spouse, former spouse or beneficiary must specify the name of the plan to which the Participant, spouse, former spouse or beneficiary wishes to have the amount transferred, on a form and in a manner prescribed by the Committee, plus such other information as may be requested by the Committee.

(d) Subsections (a) and (b) shall not apply to the following distributions:

(1) any distribution which is one of a series of substantially equal payments (not less frequently than annually) over either (1) a period of 10 years or more, or (2) a period equal to the life or life expectancy of the Participant or the joint lives or joint life expectancy of the Participant and his beneficiary,

(2) any distribution if the total distributions paid or payable from the Plan to the same individual during the same calendar year are reasonably expected by the Committee to be less than $200,

(3) that portion of any distribution after the Participant's Required Beginning Date that is required to be distributed to the Participant by the minimum distribution rules of section 401(a)(9) of the Code,

(4) such other distributions as may be exempted by applicable statute or regulation from the requirements of section 401(a)(31) of the Code.

(e) In the event of a mandatory distribution greater than $1,000 in accordance with the provisions of Section 7.8 of the Plan, if the Participant does not elect to have such distribution paid directly to an eligible retirement plan specified by the Participant in a direct rollover in accordance with this Section7.9 or to receive the distribution directly, then the distribution will be paid in a direct rollover to an individual retirement plan designated by the Committee.

7.10 Failure to Apply for Pension. Benefit payments shall commence when properly written application for same is received by the Committee. In the event that a Participant fails to apply to the Committee for pension benefits by the earlier of (a) his Normal Retirement Date or the date on which he has a Separation from Service, if later, or (b) the end of the calendar year in which he attains Age 70½, the Committee shall make diligent efforts to locate such Participant and obtain such application and, in the case of a benefit described in Section 7.8, may file an application for him if it has sufficient information to do so. In the event the Participant fails to make application by his Required Beginning Date, the Committee shall commence distribution as of the Required Beginning Date without such application. No payments shall be made for the period in which benefits would have been payable if the Participant had made timely application therefor; provided, however, that, if the Participant's Benefit Commencement Date (or, if the Participant has died, his Spouse's Benefit

Commencement Date under Section 5.8 has been delayed until after the Participant's Normal Retirement Date solely by reason of failure to make application, the benefit payable (1) to the Participant on and after his Benefit Commencement Date, or (2) to the Participant's Spouse pursuant to Section 5.8 on and after the Spouse's Benefit Commencement Date, shall be equal to the Actuarial Equivalent of the benefit the Participant or Spouse would have received had benefits commenced on the Participant's Normal Retirement Date, as determined to reflect the deferral of benefit commencement.

7.11 Mailing Address. Benefit payments and notifications hereunder shall be deemed made when mailed to the last address furnished to the Committee by the Participant or beneficiary to whom they are due.

7.12 No Reduction for Changes in Social Security. Notwithstanding any other provision of the Plan, an increase in the Social Security taxable wage base or benefit level after a Participant's Separation from Service (or his Benefit Commencement Date, if earlier) shall not reduce the amount of any benefit to which the Participant or his beneficiary was entitled prior to such increase with respect to service prior to the Participant's Separation from Service (or his Benefit Commencement Date, if earlier). Furthermore, if the Participant returns to employment as a Covered Employee, the amount of any benefit payable to such Participant at his subsequent retirement (or his Required Beginning Date, if earlier) shall not be less than the benefit that the Participant was receiving prior to his return to employment.

ARTICLE VIII

THE FUND AND FUNDING

8.1 Designation of Trustee. The Company, by appropriate resolution of its Board of Directors, shall name and designate a Trustee and shall enter into a Trust Agreement with such Trustee. The Company shall have the power, by appropriate resolution of its Board of Directors, to amend the Trust Agreement, remove the Trustee, and designate a successor Trustee, all as provided in the Trust Agreement. All of the assets of the Plan shall be held by the Trustee for use in accordance with the Plan.

8.2 Contributions to the Fund. The benefits provided under the Plan shall be financed exclusively by contributions made from time to time to the Trustee by the Participating Companies, and by the Fund created thereby. Subject to the provisions of applicable law, the liability of the Participating Companies under the Plan shall be limited to the contributions determined by the Participating Companies from time to time in accordance with the advice and counsel of the Actuary. The funding policy applicable to the Fund shall be established by the Committee and shall be reviewed from time to time. All contributions are conditioned on their deductibility for Federal income tax purposes in the taxable year that includes the first day of the Plan Year for which they are made.

8.3 Use of Contributions to the Fund. The contributions deposited under the terms of this Plan shall constitute the Fund held for the benefit of Participants and their eligible survivors under and in accordance with this Plan. No part of the corpus or income of the Fund shall be used for or diverted to purposes other than exclusively for the benefit of such Participants and their eligible survivors, and for necessary administrative costs; provided, however, that in the event of the termination of the Plan, and after all fixed and contingent

liabilities have been satisfied, and upon compliance with Sections 4041 and 4044 of ERISA, any remaining funds attributable to contributions by the Participating Companies shall revert to those companies; and further provided that in the case of a contribution (a) made by a Participating Company as a mistake of fact, or (b) which is conditioned upon the initial qualification of the Plan under section 401(a) of the Code, the Participating Company shall be entitled to a refund of said contribution within one year after payment of a contribution made as a mistake of fact, or within one year of the date on which the initial qualification of the Plan is denied by the Internal Revenue Service, as the case may be.

8.4 Trustee. The Trustee shall be the named fiduciary with respect to management and control of Plan assets held by it and shall have exclusive and sole responsibility for the custody and investment thereof in accordance with the Trust Agreement.

8.5 Forfeitures. Forfeitures shall not be applied to increase the benefits of any Participant, but shall reduce the contributions of the Participating Companies hereunder.

8.6 Expenses of Administration. All expenses of administration of this Plan shall be paid from the Fund unless they are paid directly by the Participating Companies.

8.7 Sole Source of Benefits. The Fund shall be the sole source for the provision of benefits under the Plan. Neither the Participating Companies nor any other person shall be liable therefor.

ARTICLE IX

ADMINISTRATION

9.1 Committee. If the Company designates one or more individuals as the Committee, the powers and duties of the Committee under the Plan shall be exercised by the Committee; otherwise all such powers and duties shall be exercised by the Company. The Committee shall be the named fiduciary which shall control and manage the operation of the Plan and shall administer the Plan. The Committee members may, but need not, be Employees, and they shall serve at the pleasure of the Company. They shall be entitled to reimbursement of expenses, but those members of the Committee who are also Employees of a Participating Company shall receive no compensation for their service on the Committee. Any reimbursement of expenses of the Committee members shall be paid directly by the Company. The Committee shall be responsible for the general administration of the Plan under the policy guidance of the Company.

9.2 Duties and Powers of Committee. In addition to the duties and powers described elsewhere hereunder, the Committee shall have the following specific duties and powers:

(a) to retain such consultants, accountants, attorneys, and Actuaries as may be deemed necessary or desirable to render statements, reports, and advice with respect to the Plan and to assist the Committee in complying with all applicable rules and regulations affecting the Plan; any consultants, accountants, attorneys, and Actuaries may be the same as those retained by the Company;

(b) to decide appeals under this Article;

(c) to establish a funding policy consistent with the objectives of the Plan;

(d) to enact uniform and nondiscriminatory rules and regulations to carry out the provisions of the Plan;

(e) to resolve questions or disputes relating to eligibility for benefits or the amount of benefits under the Plan;

(f) to construe and interpret the provisions of the Plan and supply any omissions in accordance with the intent of the Plan;

(g) to decide all questions of eligibility for benefits under the Plan, to determine the amount, manner and time of payment of any benefits hereunder, and to authorize the payment of benefits;

(h) to determine whether any domestic relations order received by the Plan is a qualified domestic relations order as provided in section 414(p) of the Code;

(i) to evaluate administrative procedures; and

(j) to delegate such duties and powers as the Committee shall determine from time to time to any person or persons, including the Administrator. To the extent of any such delegation, the delegate shall have the duties, powers, authority and discretion of the Committee.

Any decisions and determinations made by the Committee pursuant to this Article shall be conclusive and binding on all parties. The Committee shall have sole discretion in carrying out its responsibilities.

The expenses incurred by the Committee in connection with the operation of the Plan, including, but not limited to, the expenses incurred by reason of the engagement of

professional assistants and consultants, shall be expenses of the Plan and shall be payable from the Fund at the direction of the Committee. The Participating Companies shall have the option, but not the obligation, to pay any such expenses, in whole or in part, and, by so doing, to relieve the Fund from the obligation of bearing such expenses. Payment of any such expenses by a Participating Company on one occasion shall not bind that company to pay any similar expenses on any subsequent occasion.

9.3 Functioning of Committee. The Committee and those persons or entities to whom the Committee has delegated responsibilities shall keep accurate records and minutes of meetings, interpretations, and decisions. The Committee shall act by majority vote of the members, and such action shall be evidenced by a written document.

9.4 Disputes.

(a) In the event that the Committee denies, in whole or in part, a claim for benefits by a Participant or his beneficiary, the Committee shall furnish notice of the denial to the claimant, setting forth:

(1) the specific reasons for the denial,

(2) reference to the specific Plan provisions on which the denial is based,

(3) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary, and

(4) a description of the Plan's review procedures and the time limits applicable to such procedures, including a statement of the claimant's right to bring a civil action under section 502(a) of ERISA following an adverse benefit determination on review.

Such notice shall be forwarded to the claimant within 90 days of the Committee's receipt of the claim; provided, however, that in special circumstances the Committee may extend the response period for up to an additional 90 days, in which event it shall notify the claimant in writing of the extension, and shall specify the reason or reasons for the extension.

(b) Within 60 days of receipt of a notice of claim denial, a claimant or his duly authorized representative may petition the Committee in writing for a full and fair review of the denial. The claimant or his duly authorized representative shall be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits and shall have the opportunity to submit written comments, documents, records, and other information relating to the claim for benefits to the Committee. The Committee shall review the denial and shall communicate its decision and the reasons therefore to the claimant in writing within 60 days of receipt of the petition, after taking into account all comments, documents, records, and other pertinent information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered on the initial determination; provided, however, that in special circumstances the Committee may extend the response period for up to an additional 60 days, in which event it shall notify the claimant in writing prior to the commencement of the extension. The appeals procedure set forth in this Subsection (b) shall be the exclusive means for contesting a decision denying benefits under the Plan.

(c) It is intended that the claims procedure of this Plan be administered in accordance with the claims procedure regulations of the Department of Labor as set forth in 29 C.F.R. § 2560.503-1, or any successor thereto, and shall be deemed modified to the extent necessary to comply therewith.

9.5 Indemnification. The Administrator, each member of the Committee, and any other person who is an Employee or director of a Participating Company or an Affiliated Company shall be indemnified and held harmless by the Company against and with respect to all damages, losses, obligations, liabilities, liens, deficiencies, costs and expenses, including without limitation, reasonable attorney's fees and other costs incident to any suit, action, investigation, claim or proceedings to which he may be a party by reason of his performance of administrative functions and duties under the Plan. The foregoing right to indemnification shall be in addition to such other rights as the Administrator, Committee member, or other person may enjoy as a matter of law or by reason of insurance coverage of any kind. Rights granted hereunder shall be in addition to and not in lieu of any rights to indemnification to which the Administrator, Committee member, or other person may be entitled pursuant to the by-laws of the Participating Company.

ARTICLE X

AMENDMENT AND TERMINATION

10.1 Power of Amendment and Termination.

(a) It is the intention of each Participating Company that this Plan will be permanent. However, subject to any applicable collective bargaining agreement, each Participating Company reserves the right to terminate its participation in this Plan at any time by or pursuant to action of its board of directors or other governing body. Furthermore, the Company reserves the power to amend or terminate the Plan at any time by or pursuant to action of the Board of Directors.

(b) Each amendment to the Plan shall be binding on each Participating Company if such Participating Company, by or pursuant to action of its board of directors, (1) consents to such amendment at any time, or (2) fails to object thereto within thirty days after receiving notice thereof.

(c) Any amendment or termination of the Plan shall become effective as of the date designated by the Board of Directors. Except as expressly provided elsewhere in the Plan, prior to the satisfaction of all liabilities with respect to the benefits provided under this Plan, no amendment or termination shall cause any part of the monies contributed hereunder to revert to the Participating Companies or to be diverted to any purpose other than for the exclusive benefit of Participants and their beneficiaries.

10.2 Disposition on Termination.

(a) Upon the termination or partial termination of the Plan, each Active Participant with respect to whom the Plan is terminating (including each former Active Participant who has not received a distribution under Section 7.8 and has fewer than five

consecutive Breaks in Service) who would not have a nonforfeitable right to one hundred percent (100%) of his Accrued Benefit if his employment terminated on the date of the termination or partial termination of the Plan shall become fully vested and shall have a nonforfeitable right to his Accrued Benefit. However, in the event of such a termination, each Participant and beneficiary shall have recourse toward satisfaction of his nonforfeitable right to a pension only from Plan assets or from the Pension Benefit Guaranty Corporation, to the extent that it guarantees benefits.

(b) The amount of the Fund shall be determined and, after providing for expenses incident to termination and liquidation, the remaining assets thereof shall be allocated for the purpose of paying benefits proportionately among each of the priority groups described below in the following order of precedence:

(1) to provide benefits to retired Participants and beneficiaries who began receiving benefits at least three years before the Plan's termination (including those benefits which would have been received for at least three years if the Participant had retired that long ago), based on Plan provisions in effect five years prior to termination during which period such benefit would be the least, provided that the lowest benefit in pay status during a three-year period shall be considered the benefit in pay status for such period;

(2) to provide all other Accrued Benefits guaranteed by Federal law (or which would be so guaranteed but for section 4022(b)(5) or 4022B of ERISA);

(3) to provide all other vested Accrued Benefits (determined before application of Subsection (a) of this Section);

(4) to provide all remaining non-vested Accrued Benefits.

(c) If the assets available for allocation under any priority group (other than as provided in priority groups (3) and (4) are insufficient to satisfy in full the Accrued Benefits of all Participants and beneficiaries, the assets shall be allocated pro rata among such Participants and beneficiaries on the basis of the Actuarial Equivalent single-sum value of their respective benefits (as of the termination date). The foregoing payments, and payments in the event that assets are insufficient to pay the Accrued Benefits provided in priority groups (3) and (4), will be paid in accordance with regulations prescribed by the Pension Benefit Guaranty Corporation. The allocation of assets upon termination of the Plan will be carried out in such a manner as to preserve the qualification of the Plan under section 401(a) of the Code.

In the event that all Accrued Benefits described above have been fully funded, any remaining funds shall revert to the Participating Companies in such proportion as the Company shall determine.

10.3 Limitation on Benefits.

(a) In the event of Plan termination, the benefit payable to any highly compensated employee or any highly compensated former employee (as defined in section 414(q) of the Code and regulations thereunder) shall be limited to a benefit that is nondiscriminatory under section 401(a)(4) of the Code. If payment of benefits is restricted in accordance with this Subsection (a), assets in excess of the amount required to provide such restricted benefits shall become a part of the assets available under Section 10.2 for allocation among Participants and their joint annuitants and beneficiaries whose benefits are not restricted under this Subsection (a).

(b) The restrictions of this Subsection (b) shall apply prior to termination of the Plan to any Participant who is a highly compensated employee or a highly compensated former employee and who is one of the 25 highest paid employees or former employees of a Participating Company for any Plan Year. The annual payments to any such Participant shall be limited to an amount equal to the payments that would have been made to the Participant under a single life annuity that is the Actuarial Equivalent of the sum of the Participant's Accrued Benefit and any other benefits under the Plan.

(c) The restrictions in Subsection (b) shall not apply:

(1) if, after the payment of benefits to such Participant, the value of the Plan assets equals or exceeds 110 percent of the value of the current liabilities (within the meaning of section 412(l)(7) of the Code); or

(2) if the value of the benefit is less than one percent (1%) of the value of current liabilities.

10.4 Merger, Consolidation, or Transfer. In case of any merger or consolidation with, or transfer of assets or liabilities to, any other plan, as provided in the Code, the benefit of any Participant or beneficiary immediately after such merger, consolidation, or transfer (if the Plan had then terminated) shall be at least equal to the benefit such Participant or beneficiary would have received immediately before such merger, consolidation, or transfer (if the Plan had then terminated).

ARTICLE XI

TOP-HEAVY PROVISIONS

11.1 General. The following provisions shall apply automatically to the Plan and shall supersede any contrary provisions for each Plan Year in which the Plan is a Top-Heavy Plan (as defined below). It is intended that this Article shall be construed in accordance with the provisions of section 416 of the Code.

11.2 Definitions. The following definitions shall supplement those set forth in Article I of the Plan:

(a) "Aggregation Group" means, for any Plan Year,

(1) each qualified retirement plan of a Participating Company or an Affiliated Company in which a Key Employee is a participant,

(2) each other qualified retirement plan of a Participating Company or an Affiliated Company which enables any plan in which a Key Employee participates to meet the requirements of sections 401(a)(4) or 410 of the Code, and

(3) any or all other qualified retirement plans of a Participating Company or an Affiliated Company if (A) the plans in the Aggregation Group would be Top-Heavy Plans if each such plan were not included in the Aggregation Group but are not Top-Heavy Plans when such plan is included in the Aggregation Group, and (B) the Aggregation Group, including such plan, meets the requirements of sections 401(a)(4) and 410 of the Code.

(b) "Determination Date" means, for any Plan Year, the last day of the preceding Plan Year.

(c) "Key Employee" means, with respect to any Plan Year:

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(1) any Employee or former Employee (including any deceased Employee) who at any time during the Plan Year that includes the Determination Date was:

(A) an officer of a Participating Company having Compensation greater than $160,000 (as adjusted under section 416(i)(1)of the Code) for the calendar year in which such Plan Year ends; provided, that no more than 50 Employees (or, if less, the greater of three Employees or ten percent (10%) of the greatest number of Employees, including leased employees within the meaning of section 414(n) or 414(o) of the Code, employed by all Participating Companies and all Affiliated Companies during the Plan Year, but excluding Employees described in section 414(q)(8) of the Code) shall be treated as officers; or

(B) a five-percent (5%) owner of a Participating Company; or

(C) a one-percent (1%) owner of a Participating Company having Compensation for a Plan Year during such period in excess of $150,000; or

(2) a beneficiary of an individual described in Paragraph (1) of this Subsection.

Determinations under this Subsection shall be made in accordance with section 416(i) of the Code and the applicable regulations and other guidance issued thereunder.

(d) "Key Employee Ratio" means, for any Determination Date, the ratio of the amount described in Paragraph (1) of this Subsection to the amount described in Paragraph (2) of this Subsection, after deducting from each such amount any portion thereof described in Paragraph (3) of this Subsection, where:

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(1) the amount described in this Paragraph is the sum of (A) the present value of all accrued benefits of Key Employees under all qualified defined benefit plans included in the Aggregation Group, (B) the balances in all of the accounts of Key Employees under all qualified defined contribution plans included in the Aggregation Group, and (C) the amounts distributed from all plans in such Aggregation Group to or on behalf of any Key Employee during the one-year period ending on the Determination Date;

(2) the amount described in this Paragraph is the sum of (A) the present value of all accrued benefits of all participants under all qualified defined benefit plans included in the Aggregation Group, (B) the balances in all of the accounts of all participants under all qualified defined contribution plans included in the Aggregation Group, and (C) the amounts distributed from all plans in such Aggregation Group to or on behalf of any participant during the one-year period ending on the Determination Date; and

(3) the amount described in this Paragraph is the sum of (A) all rollover contributions (or fund to fund transfers) to the Plan by an

Employee after December 31, 1983 from a plan sponsored by an employer which is not a Participating Company or an Affiliated Company; (B) any amount that is included in Paragraphs (1) and (2) of this Subsection for a person who is a Non-Key Employee as to the Plan Year of reference but who was a Key Employee as to any earlier Plan Year; and (C) for Plan Years beginning after December 31, 1984, any amount that is included in Paragraphs (1) and (2) of this Subsection for a person who has not performed any services for any Participating Company during the five-year period ending on the Determination Date.

Clauses (d)(1)(C) and (d)(2)(C) also apply to distributions under a terminated plan which, had it not been terminated, would have been included in the Aggregation Group. In the case of a

distribution made for a reason other than severance from employment, death or disability, the term "one-year period" shall be substituted with the term "five-year period."

The present value of accrued benefits under any defined benefit plan shall be determined on the basis of the assumptions described in the definition of Actuarial Equivalent and, effective January 1, 1987, under the method used for accrual purposes for all plans maintained by all Participating Companies and Affiliated Companies if a single method is used by all such plans, or, otherwise, the slowest accrual method permitted under section 411(b)(1)(C) of the Code.

(e) "Non-Key Employee" means, for any Plan Year, (1) an Employee or former Employee who is not a Key Employee with respect to such Plan Year; and (2) a beneficiary of an individual described in Paragraph (1) of this Subsection.

(f) "Top-Heavy Compensation" means, for any Participant for any Plan Year, the average of his annual Compensation over the period of five consecutive Plan Years (or, if shorter, the longest period of consecutive Plan Years during which the Participant was in the employ of any Participating Company) yielding the highest average, disregarding (1) Compensation for Plan Years ending prior to January 1, 1984 and (2) Compensation for Plan Years after the close of the last Plan Year in which the Plan was a Top-Heavy Plan.

(g) "Top-Heavy Plan" means, for any Plan Year, each plan in the Aggregation Group for such Plan Year if, as of the applicable Determination Date, the Key Employee Ratio exceeds sixty percent (60%).

(h) "Year of Top-Heavy Service" means, for any Participant, a Plan Year in which he completes 1,000 or more Hours of Service, excluding (1) Plan Years commencing prior to January 1, 1984, (2) Plan Years in which the Plan is not a Top-Heavy Plan, and (3) Plan Years in which the Plan benefits no Key Employee or former Key Employee.

11.3 Minimum Benefit for Non-Key Employees.

(a) If the Plan is a Top-Heavy Plan in any Plan Year, each Participant who is a Non-Key Employee in such Plan Year (other than a Participant who was a Key Employee as to any earlier Plan Year) shall have a minimum Accrued Benefit. Such Accrued Benefit shall be the lesser of:

(1) two percent (2%) of the Participant's Top-Heavy Compensation multiplied by the Participant's Years of Top-Heavy Service, or

(2) twenty percent (20%) of the Participant's Top-Heavy Compensation.

(b) If a Non-Key Employee described in Subsection (a) of this Section participates in both a defined benefit plan and a defined contribution plan described in Paragraphs (a)(1) and (2) of this Section, he shall have the minimum Accrued Benefit described in this Section. In making the offset calculation for a given Plan Year, the employer-derived interest of the Employee in the defined contribution plan shall be valued as of the last valuation date preceding such Plan Year. This defined contribution plan interest shall be converted into a defined benefit by use of the assumptions set forth in the Plan's definition of "Actuarial Equivalent."

11.4 Vesting.

(a) Change in Schedule. The vested interest in his Accrued Benefit of each Participant with one or more Hours of Service in a Plan Year in which the Plan is a Top-Heavy Plan shall be determined in accordance with the following schedule unless Section 6.1 provides more rapid vesting for such Participant:

Years of Vesting Service	**Percentage Vested**
less than two years	0 percent
two years	20 percent
three years	40 percent
four years	60 percent
five years	80 percent
six years	100 percent

(b) Shift Out of Top-Heavy Status. If a Top-Heavy Plan ceases to be a Top-Heavy Plan, the vesting schedule set forth in Section 6.1 shall again apply to all Years of Service. However, a Participant described in Subsection (a) of this Section shall maintain the same vested interest in his Accrued Benefit determined under the schedule in Subsection (a) as of the date on which the Plan ceases to be a Top-Heavy Plan until the Participant's vested percentage under the schedule in Section 6.1 exceeds the percentage maintained under the schedule in Subsection (a).

(c) Special Continuation of Vesting Schedule. Each Participant described in Subsection (a) of this Section with at least three Years of Vesting Service at the time that the Plan ceases to be a Top-Heavy Plan shall continue to have his vested percentage computed under the Plan in accordance with the vesting schedule set forth in Subsection (a).

11.5 Adjustment to Maximum Benefit Limitation.

(a) For each Plan Year in which the Plan is (1) a Super Top-Heavy Plan or (2) a Top-Heavy Plan and the Board of Directors does not make the election to amend the Plan to provide the minimum benefit described in Subsection (c), the 1.25 factor in the defined benefit and defined contribution fractions described in

Article V shall be reduced to 1.0. The adjustment described in this Subsection shall not apply to a Participant during any period in which the Participant earns no additional accrued benefit under any defined benefit plan and has

no employer contributions, forfeitures, or voluntary nondeductible contributions allocated to his accounts under any defined contribution plan.

(b) In the case of any Top-Heavy Plan to which Subsection 5.10(d) applies, "$41,500" shall be substituted for "$51,875" in the calculation of the numerator of the transition fraction therein.

(c) If, in any Plan Year in which the Plan is a Top-Heavy Plan but not a Super Top-Heavy Plan, the Aggregation Group also includes a defined contribution plan, the Board of Directors may elect to use a factor of 1.25 in computing the denominator of the defined benefit and defined contribution fractions described in Article V. In the event of such election, the minimum benefit described in Subsection 11.3(a) for each Non-Key Employee who is not covered under a defined contribution plan providing the minimum benefit described in the following sentence shall be increased as follows:

(1) "three percent (3%)" shall be substituted for "two percent (2%)" in Section 11.3(a)(1), and

(2) Subsection 11.3(a)(2) shall be deemed to read, "the Participant's Top-Heavy Compensation multiplied by the sum of (A) twenty percent (20%) and (B) one percent (1%) for each Year of Top-Heavy Service, up to a maximum of 10 such Years of Top-Heavy Service."

The minimum benefit in the preceding sentence shall not apply to any Non-Key Employee who is covered under a defined contribution plan (as described in Subsection 11.3(b)) providing a minimum contribution for such Non-Key Employee of seven and one-half percent (7½%) of the Non-Key Employee's annual compensation.

11.6 Suspension of Benefits. Notwithstanding the other provisions of the Plan, the payment of a Participant's benefits shall not be suspended during the Participant's reemployment during any period in which the Plan is a Top-Heavy Plan.

ARTICLE XII

TREATMENT OF RETURNING VETERANS

12.1 Applicability and Effective Date. The rights of any Returning Veteran who resumes employment with a Participating Company on or after December 12, 1994 shall be modified as set forth in this Article.

12.2 Eligibility to Participate. For purposes of Section 2.2:

(a) A Returning Veteran who was an Active Participant immediately prior to his Qualified Military Service shall be deemed to have remained an Active Participant throughout his Qualified Military Service.

(b) A Returning Veteran who would have become an Active Participant during the period of his Qualified Military Service, but for the resulting absence from employment, shall be deemed to have become an Active Participant as of the date he would have become an Active Participant if he had not entered into Qualified Military Service.

12.3 Service. A Returning Veteran shall receive Vesting Service and Credited Service during his period of Qualified Military Service (provided that such service shall not duplicate Vesting and/or Credited Service with which he may be credited under the other provisions of the Plan).

12.4 Determination of Compensation. For purposes of determining the amount of a Participant's Accrued Benefit, and for applying the limits of Section 5.10, a Participant's Compensation during any period of Qualified Military Service shall be deemed to equal either:

(a) the Compensation he would have received but for such Qualified Military Service, based on the rate of pay he would have received from a Participating Company; or

(b) if the amount described in (a) above is not reasonably certain, his average Compensation from a Participating Company during the 12-month period immediately preceding the Qualified Military Service (or, if shorter, the period of employment immediately preceding the Qualified Military Service). Such amount shall be adjusted as necessary to reflect the length of the Participant's Qualified Military Service.

12.5 Administrative Rules and Procedures. The Committee shall establish such rules and procedures as it deems necessary or desirable to implement the provisions of this Article, provided that they are not in violation of the Uniformed Services Employment and Reemployment Rights Act of 1994, any regulations thereunder, or any other applicable law.

ARTICLE XIII

GENERAL PROVISIONS

13.1 No Employment Rights. Neither the action of the Company in establishing the Plan, nor of any Participating Company in adopting the Plan, nor any provisions of the Plan, nor any action taken by the Company, any Participating Company or the Committee shall be construed as giving to any Employee the right to be retained in the employ of the Company or any Participating Company, or any right to payment except to the extent of the benefits provided in the Plan to be paid from the Fund.

13.2 Governing Law. Except to the extent superseded by ERISA, all questions pertaining to the validity, construction, and operation of the Plan shall be determined in accordance with the laws of the state in which the principal place of business of the Company is located.

13.3 Severability of Provisions. If any provision of this Plan is determined to be void by any court of competent jurisdiction, the Plan shall continue to operate and, for the purposes of the jurisdiction of that court only, shall be deemed not to include the provisions determined to be void.

13.4 No Interest in Fund. No person shall have any interest in, or right to, any part of the principal or income of the Fund, except as and to the extent expressly provided in this Plan and in the Trust Agreement.

13.5 Spendthrift Clause. No benefit payable at any time under this Plan and no interest or expectancy herein shall be anticipated, assigned, or alienated by any Participant or beneficiary, or subject to attachment, garnishment, levy, execution, or other legal or equitable process, except for (1) a Federal tax levy made pursuant to section 6331 of the Code, (2) any

benefit payable pursuant to a domestic relations order which is determined to be a qualified domestic relations order as defined in the Code, or (3) an offset of a Participant's benefits for certain judgments or settlements described in section 401(a)(13)(C) of the Code. Any attempt to alienate or assign a benefit hereunder, whether currently or hereafter payable, shall be void.

13.6 Incapacity. If the Committee deems any Participant or beneficiary who is entitled to receive payments hereunder incapable of receiving or disbursing the same by reason of Age, illness, infirmity, or incapacity of any kind, the Committee may direct the Trustee to apply such payments directly for the comfort, support, and maintenance of such Participant or beneficiary, or to pay the same to any responsible person caring for the Participant or beneficiary who is determined by the Committee to be qualified to receive and disburse such payments for the Participant's or beneficiary's benefit; and the receipt of such person shall be a complete acquittance for the payment of the benefit. Payments pursuant to this Section shall be complete discharge to the extent thereof of any and all liability of the Participating Companies, the Committee, the Administrator, the Trustee, and the Fund.

13.7 Withholding. The Committee and the Trustee shall have the right to withhold any and all state, local, and Federal taxes which may be withheld in accordance with applicable law.

13.8 Missing Participants. In the event that all, or any portion, of the distribution payable to a Participant or his beneficiary hereunder shall, at the expiration of five (5) years after it shall become payable, remain unpaid solely by reason of the inability of the Committee, after sending a registered letter, return receipt requested, to the last known address, and after further diligent effort, to ascertain the whereabouts of such Participant or his beneficiary, the amount so distributable shall be forfeited and shall be used to reduce the cost of

the Plan. In the event a Participant or beneficiary is located after his benefit has been forfeited, such benefit shall be restored.

Executed this 9th day of November, 2010.

SM ENERGY COMPANY

By: /s/ JOHN R. MONARK
Title: Vice President - Human Resources

SCHEDULE A

MINIMUM DISTRIBUTION INCIDENTAL BENEFIT TABLES

TABLE I

Excess of Age of employee over Age of beneficiary	**Applicable percentage**
10 years or less	100 %
11	96 %
12	93 %
13	90 %
14	87 %
15	84 %
16	82 %
17	79 %
18	77 %
19	75 %
20	73 %
21	72 %
22	70 %
23	68 %
23	67 %
25	66 %
26	64 %

27	63 %
28	62 %
29	61 %
30	60 %
31	59 %
32	59 %
33	58 %
34	57 %
35	56 %
36	56 %
37	55 %
38	55 %
39	54 %
40	54 %
41	53 %
42	53 %
43	53 %
44 and greater	52 %

TABLE II

Age of Participant in calendar year preceding Required Beginning Date	Maximum Guaranteed Payments Remaining
70	26.2
71	25.3
73	24.4
74	23.5
75	22.7
76	21.8
77	20.9
78	20.1
79	19.2
80	18.4
81	17.6
82	16.8
83	16.0
84	15.3
85	14.5
86	13.8
87	13.1
88	12.4
89	11.8
90	11.1
91	10.5
92	9.9
93	9.4
94	8.8
95	7.8
96	7.3
97	6.9
98	6.5
99	6.1
100	5.7
101	5.3
102	5.0
103	4.7
104	4.4
105	4.1
106	3.8
107	3.6
108	3.4
109	3.2

110	2.8
111	2.6
112	2.4
113	2.0
114	2.0
115 and older	1.8

Appendix I
Schedule of Minimum Distribution Requirements

Section 1. General Rules.

1.1 Effective Date. The provisions of this Schedule will apply for purposes of determining required minimum distributions for calendar years beginning with the 2003 calendar year.

1.2 Precedence. The requirements of this Schedule will take precedence over any inconsistent provisions of the Plan.

1.3 Requirements of Treasury Regulations Incorporated. All distributions required under this Schedule will be determined and made in accordance with the Treasury regulations under section 401(a)(9) of the Code.

1.4 TEFRA Section 242(b)(2) Elections. Notwithstanding the other provisions of this Schedule, other than Section 1.3, distributions may be made under a designation made before January 1, 1984, in accordance with section 242(b)(2) of the Tax Equity and Fiscal Responsibility Act (TEFRA) and the provisions of the Plan that relate to section 242(b)(2) of TEFRA.

Section 2. Time and Manner of Distribution.

2.1 Required Beginning Date. The Participant's entire interest will be distributed, or begin to be distributed, to the Participant no later than the Participant's required beginning date.

2.2 Death of Participant Before Distributions Begin. If the Participant dies before distributions begin, the Participant's entire interest will be distributed, or begin to be distributed, no later than as follows:

(a) If the Participant's surviving spouse is the Participant's sole designated beneficiary, then distributions to the surviving spouse will begin by December 31 of the calendar year immediately following the calendar year in which the Participant died, or by December 31 of the calendar year in which the Participant would have attained age 70 1/2, if later.

(b) If the Participant's surviving spouse is not the Participant's sole designated beneficiary, then distributions to the designated beneficiary will begin by December 31 of the calendar year immediately following the calendar year in which the Participant died.

(c) If there is no designated beneficiary as of September 30 of the year following the year of the Participant's death, the Participant's entire interest will be distributed by December 31 of the calendar year containing the fifth anniversary of the Participant's death.

(d) If the Participant's surviving spouse is the Participant's sole designated beneficiary and the surviving spouse dies after the Participant but before distributions to the

surviving spouse begin, this Section 2.2, other than Section 2.2(a), will apply as if the surviving spouse were the Participant.

For purposes of this Section 2.2 and Section 5, distributions are considered to begin on the Participant's required beginning date (or, if Section 2.2(d) applies, the date distributions are required to begin to the surviving spouse under Section 2.2(a)). If annuity payments irrevocably commence to the Participant before the Participant's required beginning date (or to the Participant's surviving spouse before the date distributions are required to begin to the surviving spouse under Section 2.2(a)), the date distributions are considered to begin is the date distributions actually commence.

2.3 Form of Distribution. Unless the Participant's interest is distributed in the form of an annuity purchased from an insurance company or in a single sum on or before the required beginning date, as of the first distribution calendar year distributions will be made in accordance with Sections 3, 4 and 5 of this Appendix II. If the Participant's interest is distributed in the form of an annuity purchased from an insurance company, distributions thereunder will be made in accordance with the requirements of section 401(a)(9) of the Code and the Treasury regulations. Any part of the Participant's interest which is in the form of an individual account described in section 414(k) of the Code will be distributed in a manner satisfying the requirements of section 401(a)(9) of the Code and the Treasury regulations that apply to individual accounts.

Section 3. Determination of Amount to be Distributed Each Year.

3.1 General Annuity Requirements. If the Participant's interest is paid in the form of annuity distributions under the Plan, payments under the annuity will satisfy the following requirements:

(a) the annuity distributions will be paid in periodic payments made at intervals not longer than one year;

(b) the distribution period will be over a life (or lives) or over a period certain not longer than the period described in Section 4 or 5;

(c) once payments have begun over a period certain, the period certain will not be changed even if the period certain is shorter than the maximum permitted;

(d) payments will either be nonincreasing or increase only as follows:

(1) by an annual percentage increase that does not exceed the annual percentage increase in a cost-of-living index that is based on prices of all items and issued by the Bureau of Labor Statistics;

(2) to the extent of the reduction in the amount of the Participant's payments to provide for a survivor benefit upon death, but only if the beneficiary whose life was being used to determine the distribution period described in Section 4 dies or is no longer the Participant's beneficiary pursuant to a qualified domestic relations order within the meaning of section 414(p);

(3) to provide cash refunds of employee contributions upon the Participant's death; or

(4) to pay increased benefits that result from a Plan amendment.

3.2 Amount Required to be Distributed by Required Beginning Date. The amount that must be distributed on or before the Participant's required beginning date (or, if the Participant dies before distributions begin, the date distributions are required to begin under Section 2.2(a) or (b)) is the payment that is required for one payment interval. The second payment need not be made until the end of the next payment interval even if that payment interval ends in the next calendar year. Payment intervals are the periods for which payments are received, e.g., bi-monthly, monthly, semi-annually, or annually. All of the Participant's benefit accruals as of the last day of the first distribution calendar year will be included in the calculation of the amount of the annuity payments for payment intervals ending on or after the Participant's required beginning date.

3.3 Additional Accruals After First Distribution Calendar Year. Any additional benefits accruing to the Participant in a calendar year after the first distribution calendar year will be distributed beginning with the first payment interval ending in the calendar year immediately following the calendar year in which such amount accrues.

Section 4. Requirements For Annuity Distributions That Commence During Participant's Lifetime.

4.1 Joint Life Annuities Where the Beneficiary Is Not the Participant's Spouse. If the Participant's interest is being distributed in the form of a joint and survivor annuity for the joint lives of the Participant and a nonspouse beneficiary, annuity payments to be made on or after the Participant's required beginning date to the designated beneficiary after the Participant's death must not at any time exceed the applicable percentage of the annuity payment for such period that would have been payable to the Participant using the table set forth in Q&A-2 of section 1.401(a)(9)-6T of the Treasury regulations. If the form of distribution combines a joint and survivor annuity for the joint lives of the Participant and a nonspouse beneficiary and a period certain annuity, the requirement in the preceding sentence will apply to annuity payments to be made to the designated beneficiary after the expiration of the period certain.

4.2 Period Certain Annuities. Unless the Participant's spouse is the sole designated beneficiary and the form of distribution is a period certain and no life annuity, the period certain for an annuity distribution commencing during the Participant's lifetime may not exceed the applicable distribution period for the Participant under the Uniform Lifetime Table set forth in section 1.401(a)(9)-9 of the Treasury regulations for the calendar year that contains the annuity starting date. If the annuity starting date precedes the year in which the Participant reaches age 70, the applicable distribution period for the Participant is the distribution period for age 70 under the Uniform Lifetime Table set forth in section 1.401(a)(9)-9 of the Treasury regulations plus the excess of 70 over the age of the Participant as of the Participant's birthday in the year that contains the annuity starting date. If the Participant's spouse is the Participant's sole designated beneficiary and the form of distribution is a period certain and no life annuity, the period certain may not exceed the longer of the Participant's applicable distribution period, as

determined under this Section 4.2, or the joint life and last survivor expectancy of the Participant and the Participant's spouse as determined under the Joint and Last Survivor Table set forth in section 1.401(a)(9)-9 of the Treasury regulations, using the Participant's and spouse's attained ages as of the Participant's and spouse's birthdays in the calendar year that contains the annuity starting date.

Section 5. Requirements For Minimum Distributions Where Participant Dies Before Date Distributions Begin.

5.1 Participant Survived by Designated Beneficiary. If the Participant dies before the date distribution of his or her interest begins and there is a designated beneficiary, the Participant's entire interest will be distributed, beginning no later than the time described in Section 2.2(a) or (b), over the life of the designated beneficiary or over a period certain not exceeding:

(a) unless the annuity starting date is before the first distribution calendar year, the life expectancy of the designated beneficiary determined using the beneficiary's age as of the beneficiary's birthday in the calendar year immediately following the calendar year of the Participant's death; or

(b) if the annuity starting date is before the first distribution calendar year, the life expectancy of the designated beneficiary determined using the beneficiary's age as of the beneficiary's birthday in the calendar year that contains the annuity starting date.

5.2 No Designated Beneficiary. If the Participant dies before the date distributions begin and there is no designated beneficiary as of September 30 of the year following the year of the Participant's death, distribution of the Participant's entire interest will be completed by December 31 of the calendar year containing the fifth anniversary of the Participant's death.

5.3 Death of Surviving Spouse Before Distributions to Surviving Spouse Begin. If the Participant dies before the date distribution of his or her interest begins, the Participant's surviving spouse is the Participant's sole designated beneficiary, and the surviving spouse dies before distributions to the surviving spouse begin, this Section 5 will apply as if the surviving spouse were the Participant, except that the time by which distributions must begin will be determined without regard to Section 2.2(a).

Section 6. Definitions.

6.1 Designated beneficiary. The individual who is designated as the beneficiary under the Plan and is the designated beneficiary under section 401(a)(9) of the Code and section 1.401(a)(9)-1, Q&A-4, of the Treasury regulations.

6.2 Distribution calendar year. A calendar year for which a minimum distribution is required. For distributions beginning before the Participant's death, the first distribution calendar year is the calendar year immediately preceding the calendar year which contains the Participant's required beginning date. For distributions beginning after the Participant's death, the first distribution calendar year is the calendar year in which distributions are required to begin pursuant to Section 2.2.

6.3 Life expectancy. Life expectancy as computed by use of the Single Life Table in section 1.401(a)(9)-9 of the Treasury regulations.

6.4 Required beginning date. The date specified in the definition of "Required Beginning Date" set forth in Article I of the Plan.

SM ENERGY COMPANY

NON-QUALIFIED UNFUNDED SUPPLEMENTAL RETIREMENT PLAN

As Amended as of December 31, 2010

As approved by the Board of Directors, the following constitutes a non-qualified supplemental retirement benefit plan for the employees of SM Energy Company (the "Company"), as amended as of December 31, 2010.

WHEREAS:

A. The Company maintains a defined benefit retirement plan (the "DBP") qualifying under Internal Revenue Code Section 401(a) for the benefit of all eligible employees designed to pay retirement and death (survivor annuity) benefits in amounts as determined by the duly adopted and approved plan.

B. The DBP complies in all respects with the Employee Retirement Income Security Act of 1974 ("ERISA"), as amended, which establishes limits on the level of benefits which may be paid, by the DBP, including limits set forth in Section 415 of the Internal Revenue Code.

C. The Company wishes to provide to its Employees the full amount of benefits that would be payable under the benefit formula of such DBP but for the Section 415 limits, and other reductions to the benefit formula necessitated from time to time by changes to applicable law, recognizing that it cannot do so within the DBP itself and therefore the Company adopts this non-qualified retirement benefit plan (the "non-qualified plan") to supplement the DBP.

THEREFORE,

In partial consideration of the employment relationship between the Company and each of its employees, the Company agrees as follows:

1. By this non-qualified plan, no Employee shall gain any property rights in any assets of the Company. Benefits payable hereunder shall be general, unsecured liabilities of the Company, and shall be nonassignable and not subject to anticipation by Employee or Employee's beneficiary.

2. The benefits payable under this non-qualified plan shall be computed in accordance with subparagraph (i) below for employees hired by the Company after September 30, 1994, and in accordance with subparagraph (ii) below for employees hired by the Company before October 1, 1994.

(i) The benefits payable under the DBP to or for the benefit of any eligible employee hired by the Company after September 30, 1994 (a) shall be calculated without any limitation imposed by Section 415, as such Section from time to time may be amended, and (b) such benefits then shall be reduced by the benefits payable to such eligible employee under the DBP as limited by Section 415, as such Section from time to time may be amended.

(ii) The benefits payable under the DBP to or for the benefit of any eligible employee hired by the Company before October 1, 1994 (a) shall be calculated under the benefit formula of the DBP in effect on December 31, 1988, without any limitation imposed by Section 415, as such Section may from time to time be amended, and (b) such benefits then shall be reduced by the benefits payable to such eligible employee under the benefit formula of the DBP in effect beginning January 1, 1989, after amendment of the DBP in accordance with the requirements of the Tax Reform Act of 1986.

3. The time and manner of payment of benefits is as follows:

(i) Benefits under this non-qualified plan shall be payable upon the separation from service, death or disability (as defined below) of the Employee.

(ii) Benefits under this non-qualified plan shall be paid in the form of a lump-sum payment in an amount actuarially equivalent to the accrued benefit provided in Paragraph 2.

(iii) With respect to an Employee who is a "Specified Employee" as defined in Section 409A of the Internal Revenue Code and the regulations issued thereunder (referred to herein as "Section 409A"), any benefit accrued after December 31, 2004 that becomes payable by reason of such Employee's separation from service as defined in Section 409A shall be paid on (and no earlier than) the first day after the expiration of six months following the date of such Employee's separation from service, which payment shall include simple interest on the amount of each deferred payment at the short term applicable federal rate as of the date of separation from service. The amount of compensation deferred after December 31, 2004 shall be determined in accordance with Section 409A, and unless otherwise provided by Section 409A, shall be the total benefit under this non-qualified plan minus the benefit under this non-qualified plan deferred before January 1, 2005. The benefit deferred before January 1, 2005 under this non-qualified plan is the

present value, as of December 31, 2004, of the amount to which the Specified Employee would be entitled under this non-qualified plan if the Specified Employee voluntarily terminated service without cause on December 31, 2004, and received a payment of all of the benefits to which such Specified Employee would be entitled, as a lump sum, on that date. The Company may attach to this non-qualified plan a schedule setting forth the amount of benefit deferred before January 1, 2005.

(iv) For purposes of this provision, an Employee shall be considered to have separated from service if such employee shall have separated from service for any reason whatsoever within the meaning of Section 1.409A-1(h) of the Treasury regulations.

(v) For purposes of this provision, an Employee is considered to be disabled if the Employee meets either of the following requirements:

(a) The Employee is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months.

(b) The Employee is, by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, receiving income replacement benefits for a period of not less than 3 months under an accident and health plan covering other employees of the Company.

In any case, an Employee will be considered disabled if determined to be disabled by the Social Security Administration.

4. For purposes of this non-qualified plan, the beneficiary designated by an Employee shall be the same as is designated for the DBP by the Employer, or in the absence of such designation, by the terms of the DBP.

5. Nothing contained in this non-qualified plan and no action taken pursuant to the provisions of this non-qualified plan shall create or be construed to create a trust of any kind, or a fiduciary relationship between the Company and the Employee, his designated beneficiary or any other person. Any funds utilized or to be utilized to provide benefits under the provisions of this non-qualified plan shall until distribution continue for all purposes to be a part of the general funds of the Company and no person other than the Company shall by virtue of the provisions of this non-qualified plan have any interest in such funds. To the extent that any person acquires a right to

receive payments from the Company under this non-qualified plan, such right shall be no greater than the right of any unsecured general creditor of the Company.

6. Notwithstanding anything herein contained to the contrary, no payment of any then unpaid retirement or survivor benefit shall be made and all rights under the non-qualified plan of the Employee, his designated beneficiary, executors or administrators, or any other person, to receive payments thereof shall be forfeited if either or both of the following events shall occur:

(i) The Employee shall engage in any activity or conduct which in the opinion of the Board of Directors of the Company is inimical to the best interests of the Company.

(ii) After the Employee ceases to be employed by the Company he shall fail or refuse to provide advice and counsel to the Company when reasonably requested to do so.

7. If the Board of Directors of the Company shall find that any person to whom any payment is payable under this non-qualified plan is unable to care for his affairs because of illness or accident, or is a minor, any payment due (unless a prior claim therefor shall have been made by a duly appointed guardian, or other legal representative) may be paid to the spouse, a child, a parent, or a brother or sister, or to any person deemed by the Board of Directors to have incurred expense for such person otherwise entitled to payment, in such manner and proportions as the Board may determine. Any such payment shall be a complete discharge of the liabilities of the Company under this non-qualified plan.

8. Nothing contained herein shall be construed as conferring upon the Employee the right to continue in the employ of the Company as an executive or in any other capacity.

9. Benefits payable under this non-qualified plan shall not be deemed salary or other compensation to the Employee for the purpose of computing benefits to which he may be entitled under any pension plan or other arrangement of the Company for the benefit of its employees.

10. The Board of Directors of the Company shall have full power and authority to interpret, construe, amend, terminate and administer this non-qualified plan (except that any amendment or termination shall not diminish the actuarial value of the vested accrued benefit as of the date of the amendment or termination) and the Board’s interpretations and construction thereof, and actions thereunder, or the amount or recipient of the payment to be made therefrom, shall be binding and conclusive on all persons for all purposes. No member of the Board shall be liable to

any person for any action taken or omitted in connection with the interpretation and administration of this non-qualified plan unless attributable to his own willful misconduct or lack of good faith.

11. This non-qualified plan shall be construed in accordance with and governed by the laws of the State of Colorado.

12. Notwithstanding any other provision of this non-qualified plan, any reference herein to “eligible employee,” “Employee” or “Employees” shall mean an employee who is in that select group of management employees of the Company identified by the title at least as senior in Company management hierarchy as that of “Vice President.”

13. Claims for benefits shall be governed by the following provisions:

(i) Any claim for benefits under the plan shall be made in writing to the plan administrator. If a claim is denied, the plan administrator shall so notify the Employee within ninety (90) days after receipt of the claim. The notice of denial shall state (a) the specific reason for the denial of the claim: (b) specific references to the pertinent plan provisions upon which the denial is based, (c) a description of any additional material or information necessary to perfect the claim together with an explanation of why such material or information is necessary, and (d) an explanation of the claims review procedure.

(ii) Within sixty (60) days after the Employee’s receipt of notice of denial of a claim, the Employee may (a) file a request with the plan administrator that it conduct a full and fair review of the denial of the claim, (b) review pertinent documents, and (c) submit questions and comments to the administrator in writing.

(iii) The decision by the plan administrator with respect to the review must be given within sixty (60) days after receipt of the request, unless special circumstances require an extension. In no event shall the decision be delayed beyond 120 days after receipt of the request for review. The decision shall be written in a manner calculated to be understood by the Employee and shall contain specific reasons for the decision and a specific reference to the plan provisions upon which the decision is based.

14. This plan is intended in all respects to comply with the provisions of Section 409A and the Company shall interpret and administer the plan in all respects in a manner consistent with such provisions. Amounts that were deferred and vested prior to January 1, 2005 are intended to be grandfathered and exempt from Section 409A pursuant to the terms of Section 1.409A-6(a)(1) of the Treasury Regulations. In accordance with Section 1.409A-3(j)(4)(vii) of the

Treasury Regulations (or any subsequent corresponding provision of law), should there be a final determination that this plan fails to meet the requirements of Section 409A and the regulations thereunder with respect to any participant, the Company may distribute to the participant an amount not to exceed the amount required to be included in income as a result of the failure to comply with the requirements of Section 409A and the regulations.

IN WITNESS WHEREOF, the Company has caused this Non-Qualified Unfunded Supplemental Retirement Plan, as amended, to be executed by its duly authorized officers, effective as of December 31, 2010.

SM ENERGY COMPANY

By: /s/ ANTHONY J. BEST
Anthony J. Best
Chief Executive Officer and President

By: /s/ C. MARK BRANNUM
C. Mark Brannum
Secretary

EXHIBIT 10.32

SUMMARY OF COMPENSATION ARRANGEMENTS FOR NON-EMPLOYEE DIRECTORS

The following is a summary of the standard compensation arrangements for the non-employee members of the Board of Directors of SM Energy Company (the “Company”) for 2010.

For service for the fiscal period from May 26, 2010, through approximately May 25, 2011, the total annual target base compensation for each non-employee director is $160,000, excluding committee and attendance fees. As described more fully below, the actual value of compensation may be higher or lower depending on the results of the restricted stock component of director compensation. Primary director compensation is in the form of stock grants and is fully described below. The cash component of the director compensation for non-employee directors is as follows:

- Annual cash retainer of $25,000 for committee and board meeting fees; and
- Reimbursement for expenses incurred in attending Board and committee meetings.

The non-executive Chairman of the Board receives an additional $75,000 retainer for his service as Chairman, making his total annual compensation $235,000. This base compensation is in the form of restricted stock. The market price on the date of grant determines the number of shares that are issued to the director. The grants vest over the one-year Board service period and carry a one-year holding period restriction following the expiration of the vesting period as imposed by the Company.

The committee chairs will receive the following cash payments in recognition of the additional workload of their respective committee assignments. These amounts are to be paid at the beginning of the annual service period.

1. Audit Committee - $15,000

2. Compensation Committee - $15,000

3. Nominating and Corporate Governance Committee - $7,500

EXHIBIT 21.1

SUBSIDIARIES
OF
SM ENERGY COMPANY

A. Wholly-owned subsidiaries of SM Energy Company, a Delaware corporation:

1. Four Winds Marketing, LLC, a Colorado limited liability company
2. SMT Texas LLC, a Colorado limited liability company
3. Energy Leasing, Inc., an Oklahoma corporation
4. Belring GP LLC, a Delaware limited liability company
5. St. Mary Energy Louisiana LLC, a Delaware limited liability company
6. Hilltop Investments, a Colorado general partnership
7. Parish Ventures, a Colorado general partnership

B. Other subsidiaries of SM Energy Company:

1. Box Church Gas Gathering, LLC, a Colorado limited liability company (59%)

C. Partnership or limited liability company interests held by SM Energy Company:

1. Potato Creek Midstream, LLC, a Pennsylvania limited liability company (70%)
2. Wilkinson Pipeline, LLC, a Mississippi limited liability company (24%)
3. Trinity River Systems, LTD, a Texas limited partnership (21%)
4. 1977 H.B Joint Account, a Colorado general partnership (8%)
5. 1976 H.B Joint Account, a Colorado general partnership (9%)
6. 1974 H.B Joint Account, a Colorado general partnership (4%)
7. Sycamore Gas Systems, an Oklahoma general partnership (3%)

D. Partnership interests held by SMT Texas, LLC:

1. St. Mary Land East Texas LP, a Texas limited partnership (99%) (the remaining 1% interest is held by SM Energy Company)

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8, and Registration Statement Nos. 333-58273, 333-134221, 333-151779, 333-165740, and 333-170351 on Form S-8 of our reports dated February 25, 2011, relating to the consolidated financial statements of SM Energy Company (formerly St. Mary Land & Exploration Company) and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph regarding the Company's adoption of new accounting guidance) and the effectiveness of SM Energy Company and subsidiaries' internal control over financial reporting appearing in this Annual Report on Form 10-K of SM Energy Company for the year ended December 31, 2010.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 25, 2011

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of SM Energy Company for the year ended December 31, 2010. We hereby further consent to the use of information contained in our reports, and the use of our audit letter, as of December 31, 2010, relating to estimates of revenues from SM Energy Company's oil and gas reserves. We further consent to the incorporation by reference thereof into SM Energy Company's Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 333-58273, 333-134221, 333-151779, 333-165740, and 333-170351 on Form S-8.

/s/ RYDER SCOTT COMPANY, L.P.

Ryder Scott Company, L.P.
Denver, CO
February 25, 2011

EXHIBIT 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of SM Energy Company for the year ended December 31, 2010. We further consent to the incorporation by reference thereof into SM Energy Company's Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 333-58273, 333-134221, 333-151779, 333-165740, and 333-170351 on Form S-8.

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ C.H. (SCOTT) REES III, P.E
C.H. (Scott) Rees III, P.E
Chairman and Chief Executive Officer
Dallas, Texas
February 25, 2011

EXHIBIT 31.1

CERTIFICATION

I, Anthony J. Best, certify that:

1. I have reviewed this annual report on Form 10-K of SM Energy Company;

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

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

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

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

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

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

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

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

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2011

/s/ ANTHONY J. BEST
Anthony J. Best
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, A. Wade Pursell, certify that:

1. I have reviewed this annual report on Form 10-K of SM Energy Company;

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

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

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

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

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

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

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

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

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2011

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION
PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of SM Energy Company (the "Company") for the fiscal year ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Anthony J. Best, as President and Chief Executive Officer of the Company, and A. Wade Pursell, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

/s/ ANTHONY J. BEST
Anthony J. Best
President and Chief Executive Officer
February 25, 2011

/s/ A. WADE PURSELL
A. Wade Pursell
Executive Vice President and Chief Financial Officer
February 25, 2011

EXHIBIT 99.1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

FAX (303) 623-4258

621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

January 4, 2011

Ms. Kelly Sutton
Manager of Reserves
SM Energy Company
1775 Sherman Street, Suite 1200
Denver, CO 80203

Ladies & Gentlemen:

At the request of SM ENERGY Company (SM ENERGY), Ryder Scott Company (Ryder Scott) has conducted a reserves audit of the estimates of the proved reserves as of December 31, 2010 prepared by SM ENERGY's engineering and geological staff based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party reserves audit, completed on January 4, 2011 and presented herein, was prepared for public disclosure by SM ENERGY in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The estimated reserves shown herein represent SM ENERGY's estimated net reserves attributable to the leasehold interests in certain properties owned by SM ENERGY and the portion of those reserves reviewed by Ryder Scott, as of December 31, 2010. The properties reviewed by Ryder Scott incorporate SM ENERGY reserve determinations and are located in the states of Louisiana, Montana, North Dakota, New Mexico, Oklahoma, Texas, and Wyoming and in the federal waters offshore Louisiana.

The properties reviewed by Ryder Scott account for a portion of SM ENERGY's total net proved reserves as of December 31, 2010. Based on the estimates of total net proved reserves prepared by SM ENERGY, the reserves audit conducted by Ryder Scott addresses 87.6 percent of the total proved developed net liquid hydrocarbon reserves, 72.2 percent of the total proved developed net gas reserves, 66.4 percent of the total proved undeveloped net liquid hydrocarbon reserves, and 77.4 percent of the total proved undeveloped net gas reserves of SM Energy.

The properties reviewed by Ryder Scott account for a portion of SM Energy's total proved discounted future net income using SEC hydrocarbon price parameters as of December 31, 2010. Based on the reserve and income projections prepared by SM Energy, the audit conducted by Ryder Scott addresses 85.8 percent of the total proved developed discounted future net income and 60.8 percent of the total proved undeveloped discounted future net income of SM Energy.

As prescribed by the Society of Petroleum Engineers in Paragraph 2.2(f) of the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (SPE auditing standards), a reserves audit is defined as "the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about (1) the appropriateness of the methodologies employed; (2) the adequacy and quality of the data relied upon; (3) the depth and thoroughness of the reserves

estimation process; (4) the classification of reserves appropriate to the relevant definitions used; and (5) the reasonableness of the estimated reserve quantities."

Based on our review, including the data, technical processes and interpretations presented by SM Energy, it is our opinion that the overall procedures and methodologies utilized by SM Energy in preparing their estimates of the proved reserves as of December 31, 2010 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by SM Energy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

The estimated reserves presented in this report are related to hydrocarbon prices. SM Energy has informed us that in the preparation of their reserve and income projections, as of December 31, 2010, they used average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The net reserves as estimated by SM ENERGY attributable to SM Energy's interest in properties that we reviewed and the reserves of properties that we did not review are summarized as follows:

SEC PARAMETERS
Estimated Net Reserves
Attributable to Certain Leasehold Interests of
SM Energy Company
As of December 31, 2010

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves of Properties				
Audited by Ryder Scott				
Oil/Condensate - MBarrels	39,720	629	7,546	47,895
Plant Products - MBarrels	0	0	0	0

Gas — MMCF	281,099	15,712	177,323	474,134
Net Reserves of Properties				
Not Audited by Ryder Scott				
Oil/Condensate - MBarrels	4,350	1,357	3,811	9,518
Plant Products — MBarrels	0	0	0	0
Gas — MMCF	66,401	47,792	51,720	165,913
Total Net Reserves				
Oil/Condensate —MBarrels	44,070	1,986	11,357	57,413
Plant Products — MBarrels	0	0	0	0
Gas — MMCF	347,500	63,504	229,043	640,047

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. MBarrels means thousand barrels of oil.

Reserves Included in This Report

In our opinion, the proved reserves presented in this report conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “Petroleum Reserves Definitions” is included as an attachment to this report.

The various proved reserve status categories are defined under the attachment entitled “Petroleum Reserves Definitions” in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind-pipe categories.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At SM Energy’s request, this report addresses only the proved reserves attributable to the properties reviewed herein.

Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward. The proved reserves included herein were estimated using deterministic methods. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.”

Proved reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Audit Data, Methodology, Procedure and Assumptions

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods

which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely than not to be achieved.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties that we reviewed were estimated by performance methods, the volumetric method, analogy, or a combination of methods. Approximately 100 percent of the proved producing reserves attributable to producing wells and/or reservoirs that we reviewed were estimated by performance methods or a combination of methods. These performance methods include, but may not be limited to, decline curve analysis and material balance which utilized extrapolations of historical production and pressure data available through December, 2010, in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by SM Energy or obtained from public data sources and were considered sufficient for the purpose thereof.

Approximately 100 percent of the proved developed non-producing and undeveloped reserves that we reviewed were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by SM Energy for our review or which we have obtained from public data sources that were available through December, 2010. The data utilized from the analogues as well as well and seismic data incorporated into the volumetric analysis were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and

costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in conducting this review.

As stated previously, proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. To confirm that the proved reserves reviewed by us meet the SEC requirements to be economically producible, we have reviewed certain primary economic data utilized by SM Energy relating to hydrocarbon prices and costs as noted herein.

The hydrocarbon prices furnished by SM Energy for the properties reviewed by us are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

The initial SEC hydrocarbon prices in effect on December 31, 2010 for the properties reviewed by us were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used by SM Energy for the geographic area reviewed by us. In certain geographic areas, the price reference and benchmark prices may be defined by contractual arrangements.

The product prices which were actually used by SM Energy to determine the future gross revenue for each property reviewed by us reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy.

The table below summarizes SM Energy’s net volume weighted benchmark prices adjusted for differentials for the properties reviewed by us and referred to herein as SM Energy’s “average realized prices.” The average realized prices shown in the table below were determined from SM Energy’s estimate of the total future gross revenue before production taxes for the properties reviewed by us and SM Energy’s estimate of the total net reserves for the properties reviewed by us for the geographic area. The data shown in the table below is presented in accordance with SEC disclosure requirements for the geographic area we reviewed.

Geographic Area	**Product**	**Price Reference**	**Average Benchmark Prices**	**Average Realized Prices**
North America				
United States	Oil/Condensate	WTI Cushing	$79.43/Bbl	$70.63/Bbl
	Gas	Henry Hub	$4.38/MMBTU	$5.67/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in SM Energy’s individual property evaluations.

Accumulated gas production imbalances, if any, were not taken into account in the proved gas reserve estimates reviewed. The proved gas volumes included herein do not attribute gas consumed in operations as reserves.

Operating costs furnished by SM Energy are based on the operating expense reports of SM Energy and include only those costs directly applicable to the leases or wells for the properties reviewed by us. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs furnished by SM Energy are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by SM Energy were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SM Energy. The estimated cost of abandonment and salvage was included by SM Energy for properties where abandonment costs and salvage were significant. SM Energy’s estimates of the abandonment and salvage costs were accepted without independent verification. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for SM Energy’s estimate.

The proved developed non-producing and undeveloped reserves for the properties reviewed by us have been incorporated herein in accordance with SM Energy’s plans to develop these reserves as of December 31, 2010. The implementation of SM Energy’s development plans as presented to us is subject to the approval process adopted by SM Energy’s management. As the result of our inquires during the course of our review, SM Energy has informed us that the development activities for the properties reviewed by us have been subjected to and received the internal approvals required by SM Energy’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to SM Energy. Additionally, SM Energy has informed us that they are not aware of any legal, regulatory, political or economic obstacles that would significantly alter their plans.

Current costs used by SM Energy were held constant throughout the life of the properties.

SM ENERGY’s forecasts of future production rates are based on historical performance from wells currently on production. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used by SM Energy to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet

on production, sales were estimated to commence at an anticipated date furnished by SM Energy. Wells or locations that are not currently producing may start producing earlier or later than anticipated in SM Energy's estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

SM Energy's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which SM Energy owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included by SM Energy for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Certain technical personnel of SM Energy are responsible for the preparation of reserve estimates on new properties and for the preparation of revised estimates, when necessary, on old properties. These personnel assembled the necessary data and maintained the data and workpapers in an orderly manner. We consulted with these technical personnel and had access to their workpapers and supporting data in the course of our audit.

SM Energy has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In performing our audit of SM Energy's forecast of future proved production, we have relied upon data furnished by SM Energy with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by SM Energy. The data described herein were accepted as authentic and sufficient for determining the reserves unless, during the course of our examination, a matter of question came to our attention in which case the data were not accepted until all questions were satisfactorily resolved. We consider the factual data furnished to us by SM Energy to be appropriate and sufficient for the purpose of our review of SM Energy's estimates of reserves. In summary, we consider the assumptions, data, methods and analytical procedures used by SM Energy and as reviewed by us appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate under the circumstances to render the conclusions set forth herein.

Audit Opinion

Based on our review, including the data, technical processes and interpretations presented by SM Energy, it is our opinion that the overall procedures and methodologies utilized by SM Energy in preparing their estimates of the proved reserves as of December 31, 2010 comply with the current SEC regulations and that the overall proved reserves for the reviewed properties as estimated by SM Energy are, in the aggregate, reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

We were in reasonable agreement with SM Energy's estimates of proved reserves for the properties which we reviewed. As a consequence, it is our opinion that on an aggregate basis the data presented herein for the properties that we reviewed fairly reflects the estimated net reserves owned by SM Energy.

Other Properties

Other properties, as used herein, are those properties of SM Energy which we did not review. The proved net reserves attributable to the other properties account for 16.6 percent of the total proved net liquid hydrocarbon reserves and 25.9 percent of the total proved net gas reserves based on estimates prepared by SM Energy as of December 31, 2010. The other properties represent 17.3 percent of the total proved discounted future net income based on the unescalated pricing policy of the SEC as taken from reserve and income projections prepared by SM Energy as of December 31, 2010.

The same technical personnel of SM Energy were responsible for the preparation of the reserve estimates for the properties that we reviewed as well as for the properties not reviewed by Ryder Scott.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any publicly traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to SM Energy. Neither we nor any of our employees have any interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this audit, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the review of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party audit, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by SM Energy.

SM Energy makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, SM Energy has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference thereof into the Company's Post-Effective Amendment No. 1 to Registration Statement Nos. 333-30055, 333-35352, 333-88780, and 333-106438 on Form S-8 and Registration Statement Nos. 333-58273, 333-134221, 333-151779, 333-165740 and 333-170351 on Form S-8 of SM Energy of the references to our name as well as to the references to our third party report for SM Energy, which appears in the December 31, 2010 annual report on Form 10-K of SM Energy. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by SM Energy.

We have provided SM Energy with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by SM Energy and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ James L. Baird

James L. Baird, P.E.
Senior Vice President [SEAL]

/s/ Michael F. Stell

Michael F. Stell, P.E.
Texas PE License No. 56416
Managing Senior Vice President [SEAL]

JLB-MFS/sm

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company L.P. James Larry Baird was the primary technical person responsible for overseeing the estimate of the reserves.

Mr. Baird, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2006, is a Senior Vice President and also serves as Manager of the Denver office, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Baird served in a number of engineering positions with Gulf Oil Corporation, Northern Natural Gas and Questar Exploration & Production. For more information regarding Mr. Baird's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Baird earned a earned 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.

In addition to gaining experience and competency through prior work experience, the Colorado and Utah Board of Professional Engineers recommend continuing education annually, including at least one hour in the area of professional ethics, which Mr. Baird fulfills. As part of his 2009 continuing education hours, Mr. Baird attended an internally presented sixteen hours of formalized training as well as a day long public forum. Mr. Baird attended the 2009 RSC Reserves Conference, a two day Oil and Gas Reserves Course: New SEC Reporting Rules by Dr. John Lee, and various professional society presentations specifically on the new SEC regulations relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Baird attended an additional sixteen hours of formalized in-house training as well as three days of formalized external training during 2009 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, procedures and software and ethics for consultants. Mr. Baird was a keynote speaker, presenting the Changing Landscape of the SEC Reporting, at the 2009 Unconventional Gas International Conference held in Fort Worth, Texas.

Based on his educational background, professional training and more than 40 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Baird has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Michael F. Stell was the primary technical person responsible for overseeing the estimate of the reserves, future production and income.

Mr. Stell, an employee of Ryder Scott Company L.P. (Ryder Scott) since 1992, is a Managing Senior Vice President and also serves as an Engineering Group Leader responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Stell served in a number of engineering positions with Shell Oil Company and Landmark Concurrent Solutions. For more information regarding Mr. Stell's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Stell earned a Bachelor of Science degree in Chemical Engineering from Purdue University in 1979 and a Master of Science Degree in Chemical Engineering from the University of California, Berkeley, in 1981. He is a licensed Professional Engineer in the State of Texas. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Stell fulfills. As part of his 2010 continuing education hours, Mr. Stell attended an internally presented six hours of formalized training and ten hours of formalized external training covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, reserve reconciliation processes, overviews of the various productive basins of North America, evaluations of resource play reserves, evaluation of enhanced oil recovery reserves, and ethics training.

Based on his educational background, professional training and almost 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Stell has attained the professional qualifications for a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane

(CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made toTitle 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe reserves.

Shut-In
Shut-in Reserves are expected to be recovered from:
(1) *completion intervals which are open at the time of the estimate, but which have not started producing;*
(2) *wells which were shut-in for market conditions or pipeline connections; or*
(3) *wells not capable of production for mechanical reasons.*

Behind-Pipe
Behind-pipe Reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

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

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.