ST MARY LAND & EXPLORATION CO
Form 10-K
February 24, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

þ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2009
or
o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Commission file number 001-31539

ST. MARY LAND & EXPLORATION 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.)
1776 Lincoln Street, Suite 700, 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 þ No o

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

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. YesþNoo

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).

Yeso Noo

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

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

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

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

The aggregate market value of the 62,106,243 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the common stock on June 30, 2009, the last business day of the registrant's most recently completed second fiscal quarter, for $20.87 per share as reported on the New York Stock Exchange was $1,296,157,291. 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 16, 2010, the registrant had 62,777,688 shares of common stock outstanding, which is net of 126,893 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 2010 annual meeting of stockholders to be filed within 120 days after December 31, 2009.

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PART I

When we use the terms "St. Mary," "the Company," "we," "us," or "our," we are referring to St. Mary Land & Exploration Company and its subsidiaries, unless the context otherwise requires. We have included technical terms important to an understanding of our business under "Glossary of Oil and Natural Gas Terms." Throughout this document we make statements that are 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 oil and gas company engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil in North America. We were founded in 1908 and incorporated in Delaware in 1915. Our initial public offering of common stock took place in December 1992. The common stock of the Company trades on the New York Stock Exchange under the ticker "SM."

Our principal offices are located at 1776 Lincoln Street, Suite 700, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Historically, a key part of meeting the goal of building stockholder value was the successful execution and integration of niche acquisitions at attractive costs. Recently we shifted the emphasis of our efforts to focus on the exploration for and development of onshore resource plays in North America. This shift was due to the fact that, as we grew, the universe of potential niche acquisition targets became smaller and less impactful to our growth. Additionally, we believe that we will be able to create more long-term value for our stockholders by building an asset base that allows for more predictable growth in production and reserves and does not rely solely on acquisitions. Our strategy is based on the following points:

- Acquire significant leasehold positions in new and emerging resource plays
- Leverage our core competencies in drilling and completions, as well as acquisitions
- Exploit our legacy assets and optimize our asset base through divestitures of non-core assets when appropriate
- Maintain a strong balance sheet while funding the growth of the enterprise.

Significant Developments in 2009

- Broad Economic Downturn. Beginning in the latter part of 2008 and continuing into the first half of 2009 the global economy experienced a significant downturn related primarily to concerns over the U.S. financial system. The impact of the downturn spread quickly and affected a wide range of industries. There were two significant ramifications to the exploration and production industry. The first was that capital markets were essentially frozen at the beginning of 2009. Equity, debt, and credit markets were shut down. We were able to weather this initial shock as a result of our strong liquidity position and relatively limited capital commitments. The second impact to the industry was that fear of global recession and the associated negative impact on energy demand resulted in a significant decline in oil and gas prices. We significantly scaled back our operating activity in response to these price decreases. Our hedging program helped moderate the price fluctuations that we experienced, particularly in the first half of 2009. After the first quarter of 2009, the broader economy began to stabilize. The public markets for debt and equity opened up and banks began to be

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less restrictive with credit. We were able to renew our credit facility in April of 2009. The outlook for commodity prices also began to improve. The rapid decrease in activity across the exploration and production industry led many oilfield service companies to cut their prices to the benefit of ourselves and our peers as the year progressed. As industry conditions improved throughout the year, drilling activity increased in many parts of the country.

- Advancement of Resource Play Potential. From late 2007 through 2009, we established meaningful positions in several new potential resource plays, principally the Eagle Ford shale, Haynesville shale, and the Marcellus shale. Over the past year we worked to advance our understanding of these plays and move them closer to development mode. The greatest progress was made in our Eagle Ford shale program in South Texas. We successfully tested seven wells across our operated acreage position during the second half of 2009. The early results from this program suggest wells at the southern end of our acreage will produce drier gas while wells drilled further north will produce higher BTU-content gas and condensate. We are currently booking only the parallel offsets to producing wells as proved undeveloped locations. As a result, meaningful potential exists to grow proved reserves on our operated acreage because of our planned drilling activity for 2010. On our joint venture acreage in Dimmitt County, Texas, we believe these wells will produce even higher amounts of condensate and oil compared to our operated position. In the Haynesville shale program in the ArkLaTex region, a number of successful wells were drilled around our acreage position in Shelby and San Augustine counties in East Texas in 2009. The 3D seismic shoot of our acreage was recently received, and we have begun our horizontal drilling in the play. In our Marcellus shale program in north central Pennsylvania, we drilled and completed our first two horizontal wells during 2009. Initial indications from the well tests were encouraging. We are in the process of constructing the gathering system that will connect these two wells, as well as future wells, to the sales pipeline.

- Volatility in Commodity Prices. Prices in 2009 were generally more stable than in 2008. However the exploration and production sector still experienced significant volatility in the prices for crude oil and natural gas. Our operations and financial condition are significantly impacted by these prices. The spot price for NYMEX crude oil in 2009 ranged from a high of $81.04 per barrel in October to a low of $33.98 per barrel in February. The average spot price for oil during the year was $61.99 per barrel. The volatility in crude oil prices in early 2009 was driven by concern regarding global demand for oil. A volatile U.S. dollar was also a contributing factor in crude price volatility as the spot price of oil reacted to the relative weakening or strengthening of the U.S. dollar.

The spot price for gas at Henry Hub, a widely used industry measuring point, averaged $3.94 per MMBtu in 2009, with a high of $6.11 per MMBtu in January and a low of $1.88 per MMBtu in September. Natural gas prices came under pressure in 2009 as a result of lower domestic product demand caused by the weakening economy; and concerns over excess supply of natural gas due to the high productivity of several emerging shale plays in the U.S. Some of the regional markets where we sell gas have seen increased downward pressures on price as a result of high levels of activity in the regions, as well as a lack of pipeline takeaway capacity or local demand. This was most pronounced in our Mid-Continent and Rocky Mountain regions. However, local index differentials, in the areas where we sell gas, narrowed towards NYMEX Hub prices in late 2009.

- Decrease in Year-End Proved Reserve Estimates. Our estimated proved reserves decreased 11 percent to 772.2 BCFE at December 31, 2009, from 865.5 BCFE at December 31, 2008. We added 109.6 BCFE from our drilling program during the year, with our emerging resource play in the Eagle Ford shale in the Maverick Basin in South Texas contributing a significant portion of those additions. Our programs targeting the Woodford shale in eastern Oklahoma and the Bakken/Three Forks formations in the North Dakota portion of the Williston Basin also added meaningful additions in 2009. We sold 44.2 BCFE of proved reserves during the year, with roughly 90 percent of those relating to the divestiture of our coalbed methane project at Hanging Woman Basin along the border of Montana and Wyoming. The balance of the divested properties sold in 2009 related to non-strategic assets spread across our company.

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We had a net downward revision of 49.6 BCFE that consisted of 61.6 BCFE in downward engineering revisions and an upward pricing revision of 12.0 BCFE. The largest portion of the performance revision relates to producing properties in our Wolfberry tight oil program in the Permian Basin in West Texas. Well performance data collected during 2009 at our Sweetie Peck and Halff East programs that target the Wolfberry interval indicate that these assets are underperforming our year-end 2008 decline forecasts. Accordingly, we removed 37 BCFE from proved reserves in the Permian region, primarily related to the Wolfberry tight oil program. We believe a significant portion of these reserves, while not meeting the criteria to be booked as proved reserves at year-end, are likely to eventually be produced. We also had a downward performance revision of approximately 12 BCFE related to certain Cotton Valley assets in our ArkLaTex region. The pricing methodology used to determine proved reserves changed in 2009 in accordance with new rules promulgated by the SEC. Rather than using year-end pricing, companies are now required to use the 12-month average of the first of month prices for oil and gas to estimate proved reserves. This change in methodology from 2008 resulted in a higher oil price and a lower gas price in effect for determining year-end proved reserves for 2009. As a result, we recognized positive pricing revisions in our oil-weighted Rocky Mountain and Permian regions that offset the negative price revisions we recognized in the natural gas weighted Mid-Continent, ArkLaTex, and South Texas & Gulf Coast regions. Under the previous methodology of using year-end pricing for the determination of proved reserves, we would have had a four percent increase in proved reserves to approximately 897 BCFE.

Prior to and subsequent to year-end, we entered into several transactions to divest non-strategic properties across our company. Proved reserves associated with these properties are estimated to be approximately 71 BCFE and primarily relate to the previously announced Rocky Mountain oil property divestiture. Part of this divestiture package closed in mid-February 2010 and we expect the balance to close by the end of the first quarter of 2010.

- Impairment of Proved Properties. We recognized pre-tax non-cash impairments of proved properties in the amount of $174.8 million in 2009 compared with $302.2 million of proved property impairments 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 significantly impacted by both low natural gas prices and wider than normal differentials at the end of the first quarter. The ArkLaTex region was impacted by a $20.4 million impairment related to downward pricing and engineering revisions. We incurred a $14.0 million impairment of proved properties related to the write-down of certain assets located in the Gulf of Mexico for which we are relinquishing our ownership interests to satisfy our abandonment obligations.

- Abandonment and Impairment of Unproved Properties. During the year, we abandoned or impaired $45.4 million related to unproved properties. The largest specific components of the 2009 impairment and abandonment related to the Floyd Shale acreage located in Mississippi and acreage in Oklahoma. The remaining write-offs were related to acreage we believe we will not keep based on our current capital allocation plans or related to acreage that we do not believe will be prospective.

- Divestiture of Non-Strategic Properties. In 2009 we undertook an effort to sell a number of non-strategic properties in order to optimize our portfolio. The objective of these divestitures is to dispose of properties with limited future drilling potential while generating cash that can be used in the testing and development of our resource plays. During 2009 we sold roughly 44.2 BCFE of reserves, the vast majority of which related to our coalbed methane program in Hanging Woman Basin. We received $39.9 million in proceeds from the sales we closed in 2009. Subsequent to year end, we closed on a portion of our previously disclosed sale of non-strategic oil and gas properties in the Rocky Mountain region. The Wyoming sub-package was sold to Legacy Reserves Operating LP. The cash received at closing was $118.7 million before commission costs. The final sales price is subject to normal post-closing adjustments and is expected to be finalized by the end of second quarter of 2010. Additionally, subsequent to year-end, we also entered into agreements to sell the

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remaining non-core properties from our Rocky Mountain divestiture package in North Dakota for $137 million to Sequel Energy Partners LP, as well as some other minor properties for approximately $6 million. We expect these divestitures to close by the end of the first quarter of 2010. In total, these divestitures represent 71 BCFE of proved reserves.

Outlook for 2010

The general economic outlook for the country has improved compared to this time a year ago. We successfully weathered a rough 2009, and in the process advanced a number of potential resource plays and improved our financial condition.

As we enter 2010, our company is well positioned both financially and operationally. Early in 2009, we extended the maturity of our revolving credit facility and subsequently reduced outstanding borrowings on that facility during the year. As of February 16, 2010, we had $467 million available to us under the revolving credit facility. We have no debt maturities until 2012. Additionally, we believe that access to the capital markets has improved significantly since last year and that we could access capital through the public markets, if necessary. From an operational standpoint, we believe 2010 has the potential to be very promising for our company. We will be building upon our successful testing programs from 2009. We have moved the Eagle Ford shale program closer to development mode, and it will receive the largest portion of our capital budget this year. We will also be allocating more capital toward oil and rich natural gas projects, given their higher returns in the current environment. Specifically, we will be drilling more Wolfberry tight oil and Bakken/Three Forks wells in the Permian and Rocky Mountain regions, respectively. In the Haynesville shale, we have begun our horizontal drilling program. We continue to monitor service costs as the recent uptick in industry activity may pressure rates for the drilling and completion of wells higher than the levels we saw in 2009. We intend to fund these projects with our current year operating cash flows and proceeds from our previously announced non-core divestitures.

Assets

As of December 31, 2009, we had estimated proved reserves of 53.8 MMBbl of oil and 449.5 Bcf of natural gas. The 12-month average prices in effect on December 31, 2009, used to estimate proved reserves were $61.18 per barrel of oil and $3.87 per MMBtu of gas, which represent a 37 percent increase and 32 percent decrease, respectively, from prices used to estimate proved reserves as of December 31, 2008. On an equivalent basis, our proved reserves were 772.2 BCFE as of December 31, 2009, a decrease of 11 percent from 865.5 BCFE at the end of the prior year. On an equivalent basis, 82 percent of our proved reserves were classified as proved developed as of year-end. Total proved oil and gas reserves had a PV-10 value of $1.3 billion and a standardized measure value of $1.0 billion including the effect of income taxes. A reconciliation between these two amounts is shown under the Reserves section in Part I, Items 1 and 2 of this report. During 2009 our average daily production was 194.8 MMcf of gas and 17.3 MBbl of oil, for an average equivalent production rate of 298.8 MMCFE per day, which was down slightly compared with 313.1 MMCFE per day for 2008. Adjusting for production from properties sold as part of our active divestiture efforts over the last two years, production from retained properties has remained essentially flat from 285.6 MMCFE per day in 2008 to 284.7 MMCFE per day in 2009.

In 2009 we incurred costs of $419.0 million for drilling and exploration activities and acquisitions. This was 51 percent lower than the $857.7 million incurred in 2008. During 2009 we incurred exploration costs of $154.1 million compared to $92.2 million in 2008. We incurred development costs of $223.1 million in 2009, which was 62 percent lower than the $587.6 million in 2008. The decrease in development dollars and increase in exploration dollars reflects our decision to not invest capital in development projects in a low commodity price environment, particularly while service costs were declining. Moreover we ramped up our exploration efforts to accelerate our understanding of our emerging resource plays, particularly in the Eagle Ford shale, in order to put ourselves in a positive position once industry conditions improved. In 2009 we invested a total of $41.7 million on undeveloped leasehold compared to

$83.1 million in 2008. The majority of our 2009 leasing activity targeted emerging resource plays in our South Texas & Gulf Coast and Mid-Continent regions. We spent approximately $126.4 million in 2008 on undeveloped leasehold, including leasehold acquired as part of producing property acquisitions, targeting the Cotton Valley and Bakken formations in the ArkLaTex and Rocky Mountain regions, respectively. In 2009, we did not make any meaningful acquisitions.

Our operations are currently concentrated in five core operating areas in the United States. The following table summarizes the production, proved reserves, and PV-10 value of our core operating areas as of December 31, 2009.

	ArkLaTex	Mid-Continent	South Texas & Gulf Coast	Permian	Rocky Mountain	Total(1) (2)
2009 Proved Reserves						
Oil (MMBbl)	0.4	1.1	1.4	14.2	36.7	53.8
Gas (Bcf)	117.8	216.7	44.9	30.1	40.0	449.5
Equivalents (BCFE)	120.0	223.5	53.2	115.2	260.3	772.2
Relative percentage	15%	29%	7%	15%	34%	100%
Proved Developed %	65%	83%	53%	83%	93%	82%
PV-10 Values (in millions)						
Proved Developed	$ 92.1	$ 266.3	$ 50.5	$ 295.5	$ 548.7	$ 1,253.1
Proved Undeveloped (3)	0.1	(7.4)	(2.0)	34.9	5.4	31.0
Total Proved	$ 92.2	$ 258.9	$ 48.5	$ 330.4	$ 554.1	$ 1,284.1
Relative percentage	7%	20%	4%	26%	43%	100%
2009 Production						
Oil (MMBbl)	0.1	0.3	0.4	1.8	3.7	6.3
Gas (Bcf)	14.2	34.4	7.2	4.1	11.2	71.1
Equivalent (BCFE)	14.9	36.0	9.7	15.2	33.3	109.1
Avg. Daily Equivalents (MMCFE/d)	40.8	98.7	26.6	41.5	91.2	298.8
Relative percentage	14%	33%	9%	14%	30%	100%

(1) Totals may not add due to rounding.

(2) Included in the total are approximately 71 BCFE related to non-core properties that we have either divested or entered into agreements to divest subsequent to December 31, 2009.

(3) St. Mary will record proved undeveloped locations with a negative PV-10 value if we have intent to drill the well provided it generates positive net undiscounted cash flow and meets our economic criteria based on our corporate price call.

ArkLaTex Region. St. Mary’s operations in the ArkLaTex region are managed from our office in Shreveport, Louisiana. The ArkLaTex region was our first operating office, originating from an acquisition in 1992. For years the activities of this region focused on the Cotton Valley, James Lime, and Travis Peak formations in the region. In 2008 the Haynesville shale emerged as the leading potential resource play in East Texas and North Louisiana.

The ArkLaTex region incurred costs of $65.7 million in 2009 for exploration, development, and acquisition activities. This amount is 70 percent lower than the $218.4 million spent in 2008, which included $60.3 million in acquisitions targeting the Cotton Valley formation in East Texas. Significantly less money was spent on development and exploration activity in 2009 compared to 2008. With the emergence of the Haynesville shale late in 2008 and into 2009, our operating partner activity targeting the Cotton Valley and James Lime formations declined significantly as they focused on testing and developing their Haynesville shale properties. We participated in a number of partner-operated wells that focused on the Haynesville shale. Additionally, we elected to defer most of our operated horizontal Haynesville drilling until we could acquire seismic data that would help mitigate risk for larger parts of our acreage. Our 2009 operated activity in the ArkLaTex region was primarily focused on drilling wells that preserve acreage. The region’s 2009 production decreased 19 percent to 14.9 BCFE as a result of the lower levels of activity described above. Our 2009 year-end proved reserves were 120.0 BCFE, which is 29 percent lower than the 2008 year-end proved reserves of 170.0 BCFE. The decrease in proved reserves is primarily the result of 14.9 BCFE of production and 48.0 BCFE of negative pricing and engineering revisions. At year-end 2009 we have no proved reserves booked for our Haynesville potential related to our acreage in Shelby and San Augustine Counties in East Texas.

The Elm Grove Field is the highest value field in the ArkLaTex region at year-end 2009. We own interests in approximately 500 producing wells in the field and believe many of those wells have future uphole recompletion potential. Our working interest in the field is as high as 36 percent, although it varies greatly across the field. Generally, our working interest increases as one moves south in the field. The primary zones of interest in this field have historically been the Cotton Valley and Hosston. The vast majority of the value and proved reserves in this field relate to those zones. Over the past year, our operating partner has focused its drilling efforts almost exclusively in the Haynesville shale on acreage in the field where we have no working interest. As a result, we have very little PV-10 value or proved reserve volumes attributable to the Haynesville shale at the end of 2009 at Elm Grove field.

Our plans for 2010 in the ArkLaTex region are based almost entirely on testing and developing the Haynesville shale on our operated acreage. We have approximately 41,000 net acres across the region with potential for the Haynesville shale, of which 31,000 is located in Shelby and San Augustine Counties in East Texas. Roughly 70 percent of our Haynesville spending will be operated by us and will be focused on our acreage in these counties. We plan to drill seven horizontal wells targeting the Haynesville shale in 2010. We will also participate in a number of wells with operating partners in both northern Louisiana and East Texas that target the Haynesville interval. We expect that we will invest a minimal amount of capital this year on the drilling of James Lime and Cotton Valley wells, although we will have some leasehold and seismic expenditures related to those programs in 2010. In recent months, the industry has begun to test the Bossier shale, which is above the Haynesville shale. As information emerges about this interval, we could choose to test this formation in 2010. We believe a large portion of our acreage position in East Texas is also prospective for the Bossier shale.

Mid-Continent Region. St. Mary has been active in the Mid-Continent region since 1973. Operations for the region are managed by our office in Tulsa, Oklahoma. We have been active in the Anadarko Basin of western Oklahoma since our entry into the region. In recent years we have begun operating in the Arkoma Basin in eastern Oklahoma where the current focus is on horizontal development of the Woodford shale. The Mid-Continent region also oversees our Marcellus shale activity in north central Pennsylvania.

In 2009 we incurred costs of $106.8 million in the Mid-Continent region for exploration, development, and acquisition activity, which is 34 percent less than the $162.0 million deployed in 2008. Approximately $97 million was deployed in exploration and development activities in 2009, with the remainder being spent on leasing activities. The 2009 activity for the region focused on the continued development of our horizontal Woodford shale program in the Arkoma Basin and included the successful completion of two pilot programs to test the effect of near simultaneous fracture stimulation on increased density drilling. In the Anadarko Basin, we maintained a consistent level of operated activity targeting the Deep Springer formation throughout the year. We also participated in a largely non-operated program targeting the stacked washes in western Oklahoma. Lastly, we drilled and completed our first initial tests in our Marcellus shale program during the second half of 2009. Mid-Continent production in 2009 was 36.0 BCFE, an increase of 9 percent from the 33.0 BCFE produced in 2008. Proved reserves at the end of 2009 were 223.5 BCFE, a decrease of five percent from the 234.4 BCFE report for the prior year. The decrease in proved reserves was due in large part to the low gas price in effect at year end which resulted in downward pricing revisions of roughly 17 BCFE for some previously booked proved reserves. The low gas price also resulted in no new proved undeveloped reserves being added in the region at December 31, 2009.

The Centrahoma Field in the Arkoma Basin is the highest value field in the Mid-Continent region. At year-end, we have nearly 160 producing wells in the field. Over half of those wells were completed in the Woodford shale and the majority of those were drilled horizontally. The Woodford shale is the primary contributor to proved reserve volumes and PV-10 value at the Centrahoma Field. We believe there is additional drilling potential in the Woodford shale as well as uphole development in the Cromwell and Wapanucka formations.

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The largest operated portion of the Mid-Continent region's budget for 2010 relates to our emerging program targeting the Marcellus shale in north central Pennsylvania. We currently have roughly 42,000 net acres leased or optioned in the Marcellus shale. Four operated horizontal wells are planned for the year and we expect to begin drilling late in the second quarter of 2010. Additionally, we are currently in the process of constructing a gathering system through a large portion of our acreage position that will connect the first two wells we drilled in 2009 to sales as well as service future development. Our Marcellus program for 2010 also includes amounts for leasehold, facilities, and seismic costs. In the horizontal Woodford, our program for 2010 is primarily designed to preserve core acreage. Six operated horizontal wells are currently planned, and we will participate in a handful of wells that will be operated by others. In the Anadarko Basin, we have four wells planned in the successful Deep Springer program our regional team has run for the past several years. Four operated horizontal wells are planned for the horizontal Granite Wash play that is emerging in western Oklahoma. Our first horizontal Granite Wash well in this part of the play commenced drilling in December of 2009 and is still drilling as of the date of this report.

South Texas & Gulf Coast Region. St. Mary's presence in south Louisiana dates to the early 1900s when our founders acquired our namesake property in St. Mary Parish, Louisiana abutting the Gulf of Mexico. These 24,914 acres of fee land yielded $3.6 million of oil and gas royalty revenue in 2009. Our presence expanded along the Gulf Coast as a result of the acquisition of King Ranch Energy, Inc. in 1999. In 2007, we made two acquisitions in the Maverick Basin in South Texas that targeted Olmos shallow gas assets in South Texas and provided an entry into this multi-pay basin. During 2009, one of the other zones of interest, the Eagle Ford shale, was successfully tested by St. Mary and a competitor. Today, the Eagle Ford shale is one of the most promising shale plays in North America. The focus of our Houston office has steadily shifted over the last couple of years away from projects along the Gulf Coast and in the Gulf of Mexico toward programs onshore that allow for multiple years of drilling inventory.

Our capital expenditures for exploration, development, and acquisition activity in the South Texas & Gulf Coast region decreased slightly from $120.9 million in 2008 to $115.1 million in 2009. Nearly all of the capital deployed in the South Texas & Gulf Coast region in 2009 targeted formations in south western Texas, namely the Eagle Ford and Pearsall shales. We worked early in the year to increase our leasehold position in the area. Additionally, we continued to participate in a joint venture that allowed us to earn acreage by carrying a partner through completion in a series of wells. In mid-2009, we began operating on acreage where we had very high working interests, in many cases a 100 percent. The encouraging results from our earlier tests led to an increase in the number of wells drilled for 2009. To date, the results on our operated acreage have been very encouraging. On large parts of our acreage, we have seen rich-gas and condensate in the production stream which enhances the economics of these gas wells. We did not make any meaningful investments in properties along the Gulf Coast or in the Gulf of Mexico during the year. Our last operated platform in the Gulf of Mexico was largely remediated and abandoned in 2009 after being damaged by Hurricane Ike in 2008.

Production for the South Texas & Gulf Coast region in 2009 was 9.7 BCFE, a decrease of 32 percent from the 14.3 BCFE produced in 2008. The largest contributor to the decline year over year was the result of our sale of our interest in the Judge Digby Field in southern Louisiana at the end of 2008. Excluding the impact of this divestiture, production declined approximately one percent year over year. Proved reserves at the end of 2009 were 53.2 BCFE, an increase of 21 percent from the 43.8 BCFE reported in the prior year. The increase in proved reserves reflects drilling additions of 39.0 BCFE related entirely to our program in the Eagle Ford shale and were offset by downward price revisions related to our Olmos gas program. On our operated acreage targeting the Eagle Ford shale, we had seven proved developed wells which were producing at year-end. This program is at an early stage of its development and accordingly at December 31, 2009, we are booking only parallel offset locations to our producing wells as proved undeveloped locations. The result is a total of 14 proved undeveloped locations being booked as of year-end at a total of 24.6 BCFE. Our operated Eagle Ford program is the most significant asset in the South Texas & Gulf Coast region.

Our plans for 2010 in the South Texas & Gulf Coast region are focused exclusively on the Eagle Ford shale. As of year-end, we have 250,000 net acres leased or optioned, which is an increase from our previously reported total of 225,000 net acres. We operate roughly 168,000 of those net acres, most of which is at 100 percent working interest, with the balance of the acreage being located on joint venture acreage with an industry partner. We plan to drill 34 horizontal wells on our operated acreage in 2010. Part of our drilling program will be aimed at further delineating the play in order to make infrastructure commitments later this year. We currently are able to market all of our production and expect to do so in the future by working with midstream partners to ensure we have adequate takeaway and processing capacity to meet our needs. We will also be conducting a series of tests to help determine the ultimate spacing for the reservoir. Our operating partner plans to operate two to three rigs during 2010 on our joint venture acreage where we have a net working interest of 25 percent.

Permian Basin Region. The Permian Basin 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 holdings in the Permian Basin began with a series of property acquisitions in 1996. In December 2006 we made a major acquisition of oil properties that targeted the Wolfberry tight oil play. To manage the significant increase in operated properties associated with the Sweetie Peck acquisition, we opened a regional office in Midland, Texas in February 2007.

We incurred costs of $76.5 million in the region in 2009 compared to $163.2 million in 2008. This decrease in capital investment reflects the significant slowdown in our drilling activity during the first half of the year in response to the low oil prices being realized late in 2008 and early in 2009. The majority of this capital was deployed to develop projects in the Wolfberry tight oil play, which targets the stacked carbonate Wolfcamp and Spraberry formations found in the basin. We also tested other exploration concepts in the Permian during the year. Production in the region increased 9 percent over the prior year, from 13.8 BCFE in 2008 to 15.2 BCFE in 2009. Proved reserves as of the end of 2009 were 115.2 BCFE, which is a decrease of 26 percent from 2008 year-end reserves of 155.9 BCFE. The decrease in our estimate of proved reserves relate to engineering revisions on proved producing properties in our Wolfberry tight oil program. Well performance data collected during 2009 from our Sweetie Peck and Halff East assets which target the Wolfberry indicate that these assets are underperforming our year-end 2008 decline forecasts. Accordingly, we have removed 37 BCFE from proved reserves in the Permian region, primarily related to the Wolfberry tight oil program. We believe that a significant portion of these reserves, while not meeting the criteria to be booked as proved reserves at year-end, are likely to eventually be produced.

As of the end of December 2009, the Sweetie Peck assets in the Permian Basin collectively were the highest value entity in the region. Sweetie Peck field had 182 producing wells at year-end. We have slightly over 20 proved undeveloped locations booked at Sweetie Peck at year-end. We also believe there are a meaningful number of unbooked future drilling locations that we will be able to pursue in future years.

The largest drilling program planned for the Permian region in 2010 is in our Sweetie Peck tight oil assets where we plan to drill 32 operated wells this year. Most of the development will take place on 80- and 40-acre spaced locations. Despite the downward Wolfberry engineering revisions in our proved reserve estimates referred to above, these projects continue to meet our economic standards for drilling, albeit at lower proved reserve volumes. We will also continue to work on an exploratory program that began in 2009 and we plan to conduct a modest drilling program in 2010, primarily using vertical wells.

Rocky Mountain Region. St. Mary has conducted operations in the Williston Basin in eastern Montana and western North Dakota since 1991. The region is managed by our office in Billings, Montana. In recent years, we have expanded our operations into the Greater Green River, Powder River, Big Horn, and Wind River basins of Wyoming through a series of acquisitions. The largest growth in the region came in late 2001 and early 2003 with significant property acquisitions from Choctaw, Burlington Resources, and Flying J. In recent years, we have been divesting of non-core properties in the Rocky Mountain region in an effort to focus our human and investment capital on the most impactful plays in that region.

We incurred costs of $51.2 million in 2009 for exploration, development, and acquisitions in the Rocky Mountain region, compared to $190.3 million in 2008. Our 2009 budget in the Rocky Mountain region reflected the low oil prices and the wide price differentials we experienced at the end of 2008. For much of 2009, we did not have any operated rigs running in the region. Our capital investments were primarily focused on the Bakken and Three Forks formations and were heavily weighted toward the back half of the year. Proved reserves for the Rocky Mountain region were 260.3 BCFE at year-end compared with 261.4 BCFE as of the end of 2008. The slight decrease in proved reserves is the result of selling 40.3 BCFE of proved reserves in the region during the year, most of which related to the sale of non-strategic coalbed methane project at Hanging Woman Basin, offset by net positive price and engineering revisions of 50.0 BCFE. Production in the Rocky Mountain region for 2009 was 33.3 BCFE. Total regional production was down five percent from 34.9 BCFE in 2008. Adjusting for the effect of the divestitures, production in the region would have declined 1.3 BCFE, or four percent, year over year.

The Elm Coulee Field is the highest value field in the region at year-end 2009. The reserves in this field are predominately oil, and the Bakken is the formation of primary interest. The field is largely developed with only a handful of remaining drilling locations identified as proved undeveloped.

The Bakken and Three Forks formations in the Williston Basin will be our primary focus in 2010. We plan to drill 17 horizontal wells targeting these formations in 2010. The majority will be located in our Bear Den asset program in McKenzie and Williams counties in North Dakota where we have roughly 16,000 net acres. Additionally, we have built a 70,000 net acre position with potential for the Bakken and Three Forks in McKenzie, Williams, and Divide counties that we will test during 2010. We are currently drilling a test well in Wyoming targeting the Niobrara formation as part of our ongoing exploration effort. We plan to evaluate our results, as well as those of nearby competitors, during 2010.

Reserves

In December 2008, the SEC announced that it had approved revisions designed to modernize oil and gas reporting requirements. A key revision to the rules pertains to commodity prices. The economic producibility of reserves and discounted cash flows are now based on a 12-month average commodity price as opposed to a year-end price in estimating reserves. The prices used in the calculation of proved reserve estimates as of December 31, 2009, were $61.18 per Bbl and $3.87 per MMBTU for oil and natural gas, respectively. These prices were 37 percent higher and 32 percent lower, respectively, than the year-end prices used to estimate 2008 proved reserves, and 23 percent and 33 percent lower, respectively, than prices that would have been used the SEC’s previous methodology. If the SEC’s prior methodology had been used for year-end 2009 proved reserves, the prices used would have been $79.36 per Bbl and $5.79 per MMBTU.

Additional revisions to the SEC rules provide for the use of new technology to estimate proved reserves. Additionally, the definition of proved oil and gas reserves has been expanded to include non-traditional resources, which focuses on the marketable product rather than the method of extraction. In addition to these regulatory changes, in 2009 we began recording estimates of proved reserve volumes for properties that we believe are reasonably certain to generate positive net cash flows on an undiscounted basis, that we have the intent to drill, and which meet our internal economic criteria for drilling. Previously, we booked proved reserve volumes if the properties showed a positive PV-10 value, we had the intent to drill, and the wells met our economic criteria.

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, 2009. We engaged Ryder Scott Company, L.P. (“Ryder Scott”) to review internal engineering estimates for at least 80 percent of the PV-10 value of our proved reserves in 2009, 2008, and 2007, excluding our coalbed methane properties. For 2008 and 2007, 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 St. Mary’s non-operated coalbed methane interest in the Green River Basin. We divested of all Hanging Woman Basin properties in the fourth quarter of 2009.

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 in the future. 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 St. Mary. 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 2009 corporate ratio of reserves replaced through drilling activity was 100 percent. There were no material acquisitions made in 2009. Four out of our five regions did not replace their respective regional production for the year. The one exception, our South Texas & Gulf Coast region, replaced 400 percent of its production for 2009 due to the strong results in the Eagle Ford shale. This metric is calculated using information from the Oil and Gas Reserve Quantities section of Note 16 – 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 16 – 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,		
Reserves data:	2009	2008	2007
Proved developed			
Oil (MMBbl)	48.1	47.1	68.3
Gas (Bcf)	342.0	433.2	426.6
BCFE	630.3	715.8	836.3
Proved undeveloped			
Oil (MMBbl)	5.7	4.3	10.5
Gas (Bcf)	107.5	124.2	186.9
BCFE	141.9	149.7	250.2
Total Proved			
Oil (MMBbl)	53.8	51.4	78.8
Gas (Bcf)	449.5	557.4	613.5
BCFE	772.2	865.5	1,086.5
Proved developed reserves %	82%	83%	77%
Proved undeveloped reserves %	18%	17%	23%
Reserve Value info (in thousands)			
Proved developed PV-10	$ 1,253,056	$ 1,214,380	$ 3,300,213
Proved undeveloped PV-10	31,029	51,005	560,974
Total proved PV-10 value	$ 1,284,085	$ 1,265,385	$ 3,861,187
Standardized measure of discounted future cash flows	1,015,967	1,059,069	2,706,914

Reserve replacement – drilling and acquisitions, excluding revisions	100%	174%	211%
All in – including sales of reserves	14%	(93)%	248%
All in – excluding sales of reserves	55%	(39)%	249%
Reserve life (years) (1)	7.1	7.6	10.1

(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,		
	2009	2008	2007
	(In thousands)		
Standardized measure of discounted future net cash flows	$ 1,015,967	$ 1,059,069	$ 2,706,914
Add: 10 percent annual discount, net of income taxes	732,997	724,840	2,321,983
Add: future income taxes	515,953	419,544	2,316,637
Undiscounted future net cash flows	$ 2,264,917	$ 2,203,453	$ 7,345,534
Less: 10 percent annual discount without tax effect	(980,832)	(938,068)	(3,484,347)
PV-10 value	$ 1,284,085	$ 1,265,385	$ 3,861,187

Proved Undeveloped Reserves

As of December 31, 2009, we had 141.9 BCFE of proved undeveloped reserves, which is a decrease of 7.8 BCFE or five percent compared with 149.7 of proved undeveloped reserves at December 31, 2008. A negative revision of 19.1 BCFE was due to lower pricing in the gas weighted regions, particularly in the ArkLaTex region where 16.4 BCFE of mostly Cotton Valley proved undeveloped reserves became uneconomic using the new 12-month average pricing. We added 43.6 BCFE of proved undeveloped reserves through our drilling program, 34.3 BCFE of which were extensions and discoveries, primarily in the Eagle Ford shale, as well as an additional 9.3 BCFE of infill proved undeveloped reserves that were mostly concentrated in the Cotton Valley and Bakken. During the year, 7.0 BCFE were sold in divestitures, primarily in our Rocky Mountain region. We invested approximately $57 million to convert 18.6 BCFE of proved undeveloped reserves in 2009, which amounted to approximately $57 million in capital expenditures, mainly in the Wolfberry properties in the Permian region and the Woodford shale in the Mid-Continent region. We had a negative revision of 6.7 BCFE due to downward performance revisions in our Wolfberry properties in the Permian region and 3.6 BCFE of proved undeveloped reserves were removed as a result of the five year limitation on the number of years that a proved undeveloped reserve may remain on the books without being developed. As of December 31, 2009, we have no material proved undeveloped reserves that have been on the books in excess of five years. As of December 31, 2009, estimated future development costs relating to proved undeveloped reserves are projected to be approximately $49 million, $129 million, and $56 million in 2010, 2011, and 2012, respectively.

Alternate Pricing Scenario

The following table presents our December 31, 2009, reserves data and PV-10 value based on prices that would have been used under the SEC's previous methodology of estimating reserves using year-end pricing. If the SEC's prior methodology had been used for year-end 2009 proved reserves, the prices used would have been $79.36 per barrel and $5.79 per MMBTU. All cost assumptions remain the same.

	As of December 31, 2009
Reserves data:	
Proved developed	
Oil (MMBbl)	53.0
Gas (Bcf)	382.9
BCFE	700.8
Proved undeveloped	
Oil (MMBbl)	8.8
Gas (Bcf)	143.9
BCFE	196.4
Total Proved	
Oil (MMBbl)	61.8
Gas (Bcf)	526.8
BCFE	897.2
Proved developed reserves	78%
Proved undeveloped reserves	22%
Reserve Value info (in thousands)	
Proved developed PV-10	$ 2,207,906
Proved undeveloped PV-10	235,805
Total proved PV-10 value	$ 2,443,711

Internal Controls Over Reserves Estimate

St. Mary's policies regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and values in compliance with the SEC's regulations. Responsibility for compliance in reserves bookings is delegated to our reservoir engineering group, which is led by our Vice President of 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 proved reserve quantities. The reserve process is overseen by Dennis A. Zubieta, Vice President - Engineering and Evaluation for St. Mary. Mr. Zubieta joined St. Mary 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 region. This is intended to promote objective and independent analysis within the reserves process.

Third-party Reserves Audit

An independent audit is performed by Ryder Scott using their own engineering assumptions and economic data provided by St. Mary. A minimum of 80 percent of the total calculated proved reserve PV-10 value is audited by Ryder Scott. In aggregate, the reserve values of the audited properties are required to be within 10 percent of St. Mary's valuations on both a corporate and regional level. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy years. The technical person at Ryder Scott primarily responsible for overseeing the reserves audit is a Senior Vice President and holds 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 St. Mary's 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. They may also meet with the key representative from Ryder Scott to discuss their process and findings.

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 St. Mary held an interest during the periods indicated. Also presented is a production cost per MCFE summary for the Company.

	Years Ended December 31,		
	2009	2008	2007
Net production			
Oil (MMBbl)	6.3	6.6	6.9
Gas (Bcf)	71.1	74.9	66.1
BCFE	109.1	114.6	107.5
Average net daily production			
Oil (MBbl)	17.3	18.1	18.9
Gas (MMcf)	194.8	204.7	181.0
MMCFE	298.8	313.1	294.5
Average realized sales price, excluding the effects of hedging			
Oil (per Bbl)	$ 54.40	$ 92.99	$ 67.56
Gas (per Mcf)	$ 3.82	$ 8.60	$ 6.74
Per MCFE	$ 5.65	$ 10.99	$ 8.48
Average realized sales price, including the effects of hedging			
Oil (per Bbl)	$ 56.74	$ 75.59	$ 62.60
Gas (per Mcf)	$ 5.59	$ 8.79	$ 7.63
Per MCFE	$ 6.94	$ 10.11	$ 8.71
Production costs per MCFE			
Lease operating expense	$ 1.33	$ 1.46	$ 1.31
Transportation expense	$ 0.19	$ 0.19	$ 0.14
Production taxes	$ 0.37	$ 0.71	$ 0.58

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Productive Wells

As of December 31, 2009, St. Mary had working interests in 2,046 gross (1,000 net) productive oil wells and 3,154 gross (1,042 net) productive gas wells. Productive wells are either producing wells 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 have closed or plan to close on several divestitures of non-core properties, primarily in the Rocky Mountain region. Upon closing of these transactions, we will have divested 425 gross (302 net) productive oil wells and 305 gross (93 net) productive gas wells.

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 sets forth the wells drilled and recompleted in which St. Mary participated during each of the three years indicated:

	Years Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	103	29.64	221	81.46	164	77.91
Gas	74	18.15	559	205.18	518	204.62
Non-productive	3	1.29	25	13.70	30	13.18
	180	49.08	805	300.34	712	295.71
Exploratory:						
Oil	2	0.42	2	0.40	3	1.92
Gas	18	9.05	10	2.75	9	4.01
Non-productive	5	2.88	1	0.76	5	2.58
	25	12.35	13	3.91	17	8.51
Farmout or non-consent	3	-	7	-	1	-
Total(1)	208	61.43	825	304.25	730	304.22

(1) Does not include one and two gross wells completed on St. Mary's fee lands during 2009 and 2008, respectively, in which we only have royalty interests.

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 reporting to the appropriate authority that the well has been abandoned.

In addition to the wells drilled and completed in 2009 included in the table above, as of February 16, 2010, St. Mary is currently participating in the drilling of 25 gross wells, all of which are located in the continental United States. We operate nine of these wells with the remaining 16 wells being operated by our partners. On a net basis, we are drilling 7.6 net operated wells and are participating in 2.0 net non-operated wells. With respect to completion activity, there are currently 19 wells in which we have an interest that are being completed. We operate 13 of those on a gross basis (10.2 net) and is participating with industry partners in 6 gross (0.3 net) completion activities. The vast majority, if not all, of these operations relate to the drilling of wells for primary production.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leases, fee properties, mineral servitudes, and lease options held by St. Mary as of December 31, 2009. 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	147	60	1,541	223
Colorado	-	-	940	614	940	614
Kansas	-	-	2,240	560	2,240	560
Louisiana	101,516	37,483	25,120	4,905	126,636	42,388
Mississippi	2,360	429	100,963	42,265	103,323	42,694
Montana	59,806	40,389	343,612	236,463	403,418	276,852
Nevada	-	-	197,945	197,945	197,945	197,945
New Mexico	2,507	1,815	1,240	1,022	3,747	2,837
North Dakota	127,497	87,654	216,779	121,214	344,276	208,868
Oklahoma	256,577	81,184	70,483	32,917	327,060	114,101
Pennsylvania	-	-	30,462	27,440	30,462	27,440
Texas	221,795	106,072	544,683	260,955	766,478	367,027
Utah	-	-	2,568	561	2,568	561
Wyoming	88,761	52,814	285,700	143,183	374,461	195,997
	862,213	408,003	1,822,882	1,070,104	2,685,095	1,478,107
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)	880,138	422,719	1,842,066	1,088,926	2,722,204	1,511,645

(1) Developed acreage is acreage assigned to producing wells for the spacing unit of the producing formation. Developed acreage of St. Mary's properties that include 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 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 gas, regardless of whether such acreage contains estimated reserves.

(3) Subsequent to December 31, 2009, St. Mary divested certain non-core properties, which included leases covering approximately 26,100 and 25,100 developed gross and net acres, respectively, and 18,600 and 15,000 undeveloped gross and net acres, respectively. Additionally, we entered into agreements to divest certain non-core properties, which included leases covering approximately 80,200 and 44,500 developed

gross and net acres, respectively, and 63,700 and 31,000 undeveloped gross and net acres, respectively.

Delivery Commitments

As of December 31, 2009, there were no material delivery commitments. Subsequent to year end we are subject to a certain gathering through-put contract that requires a minimum volume delivery of 15 Bcf by January 1, 2013. We will be required to pay $0.18 Mcf for any shortfall in delivering the minimum volume of 15 Bcf. At the current time, the company does not have proved developed reserves to offset this contractual liability, but fully intends to develop proved undeveloped reserves that will exceed the through-put commitment.

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Major Customers

During 2009, sales to Teppco Crude Oil LLC individually accounted for 12 percent of our total oil and gas production revenue. During 2008 and 2007, no customer individually accounted for ten percent or more of our total oil and gas production revenue.

Employees and Office Space

As of February 16, 2010, we had 550 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, 2009, we lease approximately 79,000 square feet of office space in Denver, Colorado for our executive and administrative offices, of which approximately 9,000 square feet is subleased. We lease approximately 22,000 square feet of office space in Tulsa, Oklahoma; approximately 22,000 square feet in Shreveport, Louisiana; approximately 26,000 square feet in Houston, Texas; approximately 17,000 square feet in Midland, Texas; approximately 36,000 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 working interests are held pursuant to leases from third parties. A title opinion is usually obtained prior to the commencement of drilling operations. We have obtained title opinions or have conducted a thorough 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 the value of our properties is subject to a mortgage under our credit facility, customary 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 perform only a minimal title investigation before acquiring undeveloped leasehold.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and decrease during the 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, increasing summertime demand for electricity is beginning to place increased demand on storage volumes. Crude oil and the demand for heating oil are also impacted by generally higher prices in the winter and the summer driving season – although oil is much more driven by global supply and demand. Seasonal anomalies such as mild winters sometimes lessen these fluctuations. The impact of seasonality has somewhat been exacerbated by the overall supply and demand economics related to crude oil because there is a narrow margin of production capacity in excess of existing worldwide demand.

Competition

The oil and gas industry is intensely competitive, particularly with respect to capturing prospective oil and natural gas properties and oil and gas reserves. We believe our leasehold position provides a sound foundation for a solid drilling program. Our competitive position also depends on our geological, geophysical, and engineering expertise, and our financial resources. We believe the location of our leasehold acreage, our exploration, drilling, and production expertise and available technologies, and the experience and knowledge of our management and industry partners enable us to compete effectively in our core operating and resource play areas. Notwithstanding our talents and assets, we still face stiff competition from a substantial number of major and independent oil and gas companies who 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 natural gas companies in attempting to secure drilling rigs and other equipment and services necessary for the drilling and completion of wells. Consequently, we may face shortages or delays in securing these services from time to time. We are seeing signs of tightening rig availability, although it is quite specific by region. The oil and natural gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may be affected by future legislation and regulations as the U.S. develops new energy and climate-related policies. Finally, we also compete for people. Throughout the industry, the need to attract and retain talented people has grown at a time when the number of 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 government 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 which 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) or the Minerals Management Service (MMS). 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 or MMS 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 or the MMS, as applicable, may require our operations on federal leases to be suspended or terminated.

In January 2010, the BLM announced that it will be issuing a new draft oil and gas leasing policy that will 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. As the policy has not yet been released, we are not able to determine the impact these potential leasing policy changes may have on our business.

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 recently 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, possible regulations 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 - Possible regulations related to global warming or climate change could have an adverse effect on our operations and the demand for oil and natural gas."

Hydraulic fracturing is a common process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable oil or natural gas to move more easily through the rock pores to a production well. This process is often necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing techniques in many of our reservoirs, and our shale resource programs utilize or contemplate the utilization of hydraulic fracturing. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. Legislative and regulatory efforts at the federal level and in some states have been made which could result in additional regulations and permitting requirements. Those additional regulations and permitting requirements, as well as other regulatory developments, could lead to significant operational delays and increased operating costs, and make it more difficult to perform hydraulic fracturing.

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 ex 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

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- Proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation
- Future oil and natural gas production estimates
- Our outlook on future oil and natural gas prices 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
- 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 Form 10-K.

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 Form 10-K, and include such factors as:

- The volatility and level of realized oil and natural gas prices
- A contraction in demand for oil and natural gas as a result of adverse general economic conditions or climate change initiatives
- The availability of economically attractive exploration, development, and property acquisition opportunities and any necessary financing, including any constraints on the availability of opportunities and financing due to distressed capital and credit market conditions
- Our ability to replace reserves and sustain production
- Unexpected drilling conditions and results
- Unsuccessful exploration and development drilling
- The risks of hedging strategies, including the possibility of realizing lower prices on oil and natural gas sales as a result of commodity price risk management activities
- The pending nature of reported divestiture plans for certain non-core oil and gas properties as well as the ability to complete divestiture transactions
- The uncertain nature of the expected benefits from acquisitions and divestitures of oil and natural gas properties, including uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities, and uncertainties with respect to the amount of proceeds that may be received from divestitures
- The imprecise nature of oil and natural gas reserve estimates

- Uncertainties inherent in projecting future rates of production from drilling activities and acquisitions

- Declines in the values of our oil and natural gas properties resulting in impairment charges and write-downs
- The ability of purchasers of production to pay for amounts purchased
- Drilling and operating service availability
- Uncertainties in cash flow
- The financial strength of hedge contract counterparties and credit facility participants, and the risk that one or more of these parties may not satisfy their contractual commitments
- The negative impact that lower oil and natural gas prices could have on our ability to borrow and fund capital expenditures
- The potential effects of increased levels of debt financing
- Our ability to compete effectively against other independent and major oil and natural gas companies and
- Litigation, environmental matters, the potential impact of government regulations, and the use of management estimates.

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.stmaryland.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 Form 10-K and should not be considered part of this document.

Glossary of Oil and Natural Gas Terms

The oil and natural gas terms defined in this section are used throughout this Form 10-K. The definitions of the terms developed reserves, exploratory well, field, proved reserves, and undeveloped reserves have been abbreviated from the respective definitions under Rule 4-10(a) of Regulation S-X promulgated by the SEC. 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 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 volumetric ratio of six Mcf of natural gas to one Bbl of oil.

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

Developed reserves. With respect to reserves as of December 31, 2009, and dates thereafter, the applicable SEC definition of developed reserves is 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. With respect to reserves as of dates prior to December 31, 2009, the applicable SEC definition of proved developed reserves was proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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. With respect to wells as of December 31, 2009, and dates thereafter, the applicable SEC definition of 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 natural gas in another reservoir. With respect to wells as of dates prior to December 31, 2009, the applicable SEC definition of exploratory well was a well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known 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 15 – Oil and Gas Activities and Note 16 – 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 barrels of oil equivalent. Oil equivalents are determined using the volumetric ratio of six Mcf of natural gas to one Bbl of oil.

MMBOE. One million barrels of oil equivalent. Oil equivalents are determined using the volumetric ratio of six Mcf of natural gas to one Bbl of oil.

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 volumetric ratio of six Mcf of natural gas 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 volumetric ratio of six Mcf of natural gas to one Bbl of oil.

MMBtu. One million British Thermal Units. A British Thermal Unit is the amount of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

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.

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. With respect to reserves as of December 31, 2009, and dates thereafter, the applicable SEC definition of proved reserves is 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. 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.

Recompletion. A 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
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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 16 – 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 area 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.

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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 Form 10-K.

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 or 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. With respect to reserves as of December 31, 2009, and dates thereafter, the applicable SEC definition of undeveloped reserves provides that 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.

ITEM 1A. RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be carefully considered when evaluating St. Mary.

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 transportation or refining facilities in regional or localized areas that may affect the realized price for oil 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
- 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.

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 global 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

- our commodity hedging arrangements could become 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 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. When 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.

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

The debt and equity financing markets have recently been constrained due to the global and domestic economic and financial downturn, and it is possible that circumstances may arise where one or more of the twelve participating banks in our credit facility, at some point, may not be able to fulfill their portion of the lending commitments to us under the facility. Adverse conditions in the credit markets may increase the cost of borrowings and decrease our ability to access new sources of capital.

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 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 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 Form 10-K 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, 2009, approximately 18 percent, or 142 BCFE, of our estimated proved reserves were proved undeveloped, and approximately 9 percent, or 73 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 $296 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 $44 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 2010 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 Form 10-K 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, 2009, were estimated using a calculated 12-month average sales price of $3.87 per MMBtu of natural gas (NYMEX Henry Hub spot price) and $61.18 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 2009, our monthly average realized natural gas prices, excluding the effect of hedging, were as high as $5.48 per Mcf and as low as $2.96 per Mcf. For the same period, our monthly average realized oil prices before hedging were as high as $70.31 per Bbl and as low as $30.37 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
- 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, 2009, have been prepared under the SEC’s new rules for oil and gas reporting that are 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 or write-downs in our reserves.

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 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
- Shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, chemicals, and supplies.

The prevailing prices of oil and natural gas affect the cost of and the demand for drilling rigs, production equipment, and 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, Haynesville, and Marcellus shales, may be more uncertain than in shale plays that are more developed and have longer established production histories. For 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. Moreover, the recent growth in exploration in the Marcellus shale has drawn intense scrutiny from environmental interest groups, regulatory agencies, and other governmental entities. 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 drilling location inventories for multi-year programs scheduled out over several years. 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.

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 significant portion of anticipated future production from our currently producing properties using zero-cost collars and swaps. As of December 31, 2009, we were in a net accrued liability position of approximately $81 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
- 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 adversely affected 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

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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 energy 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. 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 the carrying value of our properties quarterly 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 revolving credit facility.

Our revolving credit facility has a maximum commitment amount of $678 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 $900 million, which was determined as of September 29, 2009. Declines in oil or natural gas prices in the future could limit our borrowing base and reduce our ability to borrow under the credit facility. Additionally, the pending divestitures of non-core 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, 2009, we had $267 million, net of debt discount, of total long-term senior unsecured debt outstanding under our 3.50% Senior Convertible Notes due 2027, and $188 million of secured debt outstanding under our revolving credit facility. As of February 16, 2010, we had an outstanding balance of $211.0 million drawn against our revolving credit facility, resulting in $467.0 million of available debt capacity under our revolving credit facility assuming the borrowing conditions of this facility were met. Our long-term debt represented 32 percent of our total book capitalization as of December 31, 2009.

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

- 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 revolving 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. The indenture for our 3.50% Senior Convertible Notes due 2027 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 instruments, including our revolving credit facility agreement, also permit us to incur additional debt in the future. In addition, the entities we may acquire in the future could have significant amounts of debt outstanding which we could be required to assume in connection with the acquisition, or we may incur our own significant indebtedness to consummate an acquisition.

As discussed above, our revolving 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.

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, 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 presented. Accordingly, we may be subject to liability or may lose substantial portions of certain properties 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, safety standards, 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.

The U.S. Congress is currently considering legislation that would amend the Safe Drinking Water Act to eliminate an existing exemption from federal regulation of hydraulic fracturing activities and require the disclosure of chemical additives used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing is a common process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable oil or natural gas to move more easily through the rock pores to a production well. This process is often necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing techniques in many of our reservoirs, and our Eagle Ford, Haynesville, Marcellus, and Woodford shale programs utilize or contemplate the utilization of hydraulic fracturing. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. If adopted, the proposed amendment to the Safe Drinking Water Act could result in additional regulations and permitting requirements at the federal level. In addition, various states are also studying or considering various additional regulatory measures related to hydraulic fracturing. Additional regulations and permitting requirements could lead to significant operational delays and increased operating costs, and make it more difficult to perform hydraulic fracturing.

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.

In 2009, the "Oil Industry Tax Break Repeal Act of 2009" was introduced in the U.S. Senate. This bill proposes amendments to the Internal Revenue Code of 1986 to eliminate or reduce certain federal income tax incentives and deductions currently available to oil and gas exploration and production companies. The proposed amendments include the elimination or reduction of current deductions for intangible drilling and development costs, percentage depletion allowances, and the manufacturing deduction for oil and gas properties. President Obama's proposed Fiscal Year 2011 Budget also contemplates these proposed tax law amendments. If some or all of these provisions are enacted into law, our effective tax rate and current income tax expense will increase, potentially significantly, which would increase cash requirements to pay income tax thereby reducing cash flows from operating activities, which in turn will reduce cash available for drilling and other exploration and development activities.

Enactment of a Pennsylvania severance tax on natural gas could adversely impact the economic viability of exploiting natural gas drilling and production opportunities in our Marcellus Shale resource play.

The Governor of the Commonwealth of Pennsylvania has proposed to its legislature the adoption of a severance tax on the production of natural gas in Pennsylvania. The amount of the proposed tax is five percent of the value of the natural gas at the wellhead, plus $0.047 per Mcf of natural gas severed. Our Marcellus Shale acreage is located in Pennsylvania. If Pennsylvania adopts such a severance tax, it could impact the economic viability of exploiting natural gas drilling and production opportunities in the Marcellus Shale.

Possible legislation and regulations related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

On December 15, 2009, the U.S. Environmental Protection Agency (EPA) officially published its findings that emissions of carbon dioxide, which is a byproduct of the burning of refined oil products and natural gas, methane, which is a primary component of natural gas, and other "greenhouse gases" present an endangerment to human 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. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur increased costs to reduce emissions of greenhouse gases associated with our operations and could adversely affect demand for the oil and natural gas that we produce.

In addition, on June 26, 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009" (ACESA), which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020, and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. The cost of these allowances would be expected to escalate significantly over time. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions, and the Obama administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system. In addition, several states have considered initiatives to regulate emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and/or regional greenhouse gas cap and trade programs. Although it is not possible at this time to predict when the U.S. Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal or state laws or regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect the demand for the oil and natural gas that we produce.

The adoption of derivatives legislation by Congress and related regulations could have an adverse impact on our ability to hedge risks associated with our business.

The U.S. Congress is currently considering legislation to increase the regulatory oversight of the over-the-counter derivatives markets in order to promote more transparency in those markets, and impose restrictions on certain derivatives transactions, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission (CFTC) to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC's expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The Chairman of the CFTC has announced that the CFTC intends to conduct hearings to determine whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. In addition, the Treasury Department recently has indicated that it intends to propose legislation to subject all OTC derivative dealers and all other major OTC derivative market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strong business conduct standards. Derivative contracts that are not cleared through central clearinghouses and exchanges may be subject to substantially higher capital and margin requirements. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any new laws or regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and otherwise manage our financial risks related to swings in oil and gas commodity prices, may impose additional restrictions on our trading and commodity positions, and could have an adverse effect on our ability to hedge risks associated with our business and on the cost of our hedging activity.

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

The marketability of our oil and natural gas production depends in part on the availability, proximity, and capacity of pipeline transportation and gathering systems owned by third parties. The lack of available transportation capacity on these systems and facilities could result in the shutting-in of producing wells, the delay or discontinuance of development plans for properties, or lower price realizations. Although we have some contractual control over the 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

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destruction of pipelines, and general economic conditions could adversely affect our ability to produce, gather, and transport oil and natural gas.

In particular, if drilling in the Eagle Ford, Haynesville, and Marcellus shales continues to be successful, the amount of natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are being considered for these areas may not be developed due to lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells to wait for a pipeline connection or capacity and/or sell natural gas 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 natural gas and oil 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 or gathering system access, 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.

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, 2009 to February 16, 2010, the closing daily sales price of our common stock as reported by the New York Stock Exchange ranged from a low of $11.58 per share to a high of $37.89 per share. 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
- Changes in the national and global economic outlook.

We may fail to meet 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 St. Mary, 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, even though such takeover may be desired by a majority of our stockholders or may involve a premium over the prevailing stock price.

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 16, 2010, 62,590,571 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 1,271,292 shares of our common stock were outstanding, of which all were exercisable. These options are exercisable at prices ranging from $7.97 to $20.87 per share. In addition, restricted stock units providing for the issuance of up to a total of 403,968 shares of our common stock and 1,141,113 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 16, 2010, there were 62,777,688 shares of common stock outstanding, which is net of 126,893 treasury shares.

We may not always pay dividends on our common stock.

The 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. 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

St. Mary 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.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of our security holders during the fourth quarter of 2009.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the names, ages and positions held by St. Mary's executive officers. The age of the executive officers is as of February 16, 2010.

Name	Age	Position
Anthony J. Best	60	Chief Executive Officer and President
Javan D. Ottoson	51	Executive Vice President and Chief Operating Officer
A. Wade Pursell	44	Executive Vice President and Chief Financial Officer
Mark D. Mueller	45	Senior Vice President and Regional Manager
Milam Randolph Pharo	57	Senior Vice President and General Counsel
Paul M. Veatch	43	Senior Vice President and Regional Manager
Stephen C. Pugh	51	Senior Vice President and Regional Manager
Kenneth J. Knott	45	Vice President – Business Development and Land and Assistant Secretary
Gregory T. Leyendecker	52	Vice President and Regional Manager
John R. Monark	57	Vice President – Human Resources
Lehman E. Newton, III	54	Vice President and Regional Manager
David J. Whitcomb	47	Vice President – Marketing
Dennis A. Zubieta	43	Vice President – Engineering and Evaluation
Mark T. Solomon	41	Controller

Anthony J. Best joined St. Mary 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 St. Mary 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 a period as President - ARCO

Permian, President - ARCO Latin America, Field Manager for Prudhoe Bay and VP - External Affairs for ARCO Alaska.

Javan D. Ottoson joined St. Mary in December 2006 as Executive Vice President and Chief Operating Officer. Mr. Ottoson has been in the oil and gas industry for over 25 years. From April 2006 until he joined St. Mary 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

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ran his family farm. Prior to 2000 Mr. Ottoson worked for ARCO in management and operational roles. These roles included President of ARCO China, Commercial Director of ARCO British, and Vice President of Operations and Development, ARCO Permian.

A. Wade Pursell joined St. Mary 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 1997 he was with Arthur Andersen LLP, lastly as an Experienced Manager specializing in the offshore services industry.

Mark D. Mueller joined St. Mary 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 22 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.

Milam Randolph Pharo was appointed Senior Vice President and General Counsel in August 2008. He joined St. Mary as Vice President – Land and Assistant Secretary in January 1996. In May 1998 he was appointed Vice President – Land and Legal and Assistant Secretary. From 1979 until joining St. Mary, Mr. Pharo served in private practice as an attorney specializing in oil and gas matters.

Paul M. Veatch was appointed Senior Vice President and Regional Manager in March 2006. Mr. Veatch joined St. Mary in April 2001 as Regional A & D Engineer. He was 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.

Stephen C. Pugh joined St. Mary as Senior Vice President and Regional Manager of the ArkLaTex Region in July 2007. Mr. Pugh has over 27 years of experience in the oil and gas industry. Prior to joining St. Mary, Mr. Pugh was Managing Director for Scotia Waterous, a global leader in oil and gas merger and acquisition advisory services. Mr. Pugh was responsible for new business development, managing client relationships and providing merger and acquisition advice, including transaction execution to clients in the energy sector. Mr. Pugh held this position from July 2006 to July 2007. 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.

Gregory T. Leyendecker was appointed Vice President and Regional Manager in July 2007. Mr. Leyendecker joined St. Mary in December 2006 as Operations Manager for the South Texas & Gulf Coast Region in Houston. Mr. Leyendecker has worked for 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 this time 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 St. Mary, 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.

John R. Monark was appointed Vice President – Human Resources in July 2008. Mr. Monark joined St. Mary in May of 2008 as Director of Human Resources. Mr. Monark was Director – Human Resources for JF Shea Corporation, a leading construction and homebuilding company, from 2004 to May 2008. He served as Vice President – Human Resources for Pameco Corporation, a distributor of HVAC systems and equipment and refrigeration products, from 2000 to 2004. From 1996 to 2000 he served as Vice President – Human Resources for CH2M HILL.

Lehman E. Newton, III joined St. Mary in December 2006 as General Manager for the Midland office and was appointed Vice President and Regional Manager of the Permian region in June 2007. Mr. Newton has over 28 years of experience in engineering, operations, and business development roles in the exploration and production 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 E&P firm, from June 2000 to January 2003. Prior to that, Mr. Newton spent 21 years with ARCO in various engineering, operations and management roles. These assignments included Asset Manager, ARCO's East Texas operations, Vice President, Business Development, ARCO Permian, and Vice President of Operations and Development, ARCO Permian.

Kenneth J. Knott was appointed Vice President – Business Development and Land and Assistant Secretary in August 2008. Mr. Knott joined St. Mary in November 2000 as Senior Landman for the South Texas & Gulf Coast region in Lafayette, LA and later assumed the position of South Texas & Gulf Coast Regional Land Manager when the office was moved to Houston in March 2004. Mr. Knott has worked for 22 years in the energy industry holding various Land and Business Development positions with ARCO, Vastar Resources, and BP Amoco. Between 1987 and 1993, Mr. Knott worked for ARCO in a land capacity handling land and business development responsibilities in several geographic areas, such as Permian, Mid-Continent, Michigan, and California. Upon ARCO's spin-off of Vastar Resources in 1993, he joined Vastar Resources as a Senior Landman working the Gulf Coast and Gulf of Mexico regions until 1999, at which time he assumed the role of Director of Business Development for the Gulf Coast region. He remained in that capacity until the merger of Vastar Resources into BP Amoco in September 2000, whereby he assumed a Senior Landman position working the Gulf Coast region.

David J. Whitcomb was appointed Vice President – Marketing in August 2008. Mr. Whitcomb joined St. Mary in November 1994 as Gas Contract Analyst and was named Assistant Vice President of Gas Marketing in October 1995. In March 2007 his responsibilities were expanded to include oil marketing at which time his title was changed to Assistant Vice President – Director of Marketing. From 1991 until the time of his employment with St. Mary, Mr. Whitcomb worked for Anderman/Smith Operating Company as a Gas Contract Analyst during which time his primary responsibility was to resolve take-or-pay gas contract disputes. Mr. Whitcomb began his career in the industry in 1986 with Apache Corporation where he worked as an internal auditor for several years and then moved into marketing where he worked as a Gas Controller and Gas Contracts Analyst.

Dennis A. Zubieta was appointed Vice President – Engineering and Evaluation in August 2008. Mr. Zubieta joined St. Mary 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 (formerly known as Meridian Oil, Inc.) from June 1988 to May 2000 in various operations and reservoir engineering capacities.

Mark T. Solomon was appointed Controller in January 2007. Mr. Solomon was also appointed 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 St. Mary 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 St. Mary, Mr. Solomon was an auditor with Ernst & Young.

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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. St. Mary's common stock is currently traded on the New York Stock Exchange under the symbol SM. The range of high and low closing prices for the quarterly periods in 2009 and 2008, as reported by the New York Stock Exchange:

Quarter Ended	High	Low
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
December 31, 2008	$ 35.81	$ 14.76
September 30, 2008	65.58	32.53
June 30, 2008	65.00	37.73
March 31, 2008	39.95	31.70

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PERFORMANCE GRAPH

The following performance graph compares the cumulative return on St. Mary's common stock, not including dividend payments, for the period beginning December 31, 2004, and ending on December 31, 2009, 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

"Performance Graph" shall be deemed to be "furnished" but not "filed" with the Securities and Exchange Commission.

Holders. As of February 16, 2010, the number of record holders of St. Mary's common stock was 111. Based on inquiry, management believes that the number of beneficial owners of our common stock is approximately 17,000.

Dividends. St. Mary has paid cash dividends to 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 2009. 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 the limitation of our annual dividend rate to no more than $0.25 per share per year. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $6.2 million in 2009 and $6.2 million in 2008.

Equity Incentive Compensation Plan. In May 2009, the shareholders approved an amendment to rename the 2006 Equity Incentive Compensation Plan to the Equity Incentive Compensation Plan (the "Equity Plan").

Restricted Shares. St. Mary has no restricted shares outstanding as of December 31, 2009, aside from Rule 144 restrictions on shares for insiders, shares are subject to transfer restrictions under the provisions of the Employee Stock Purchase Plan, and shares issued to directors under the Equity Plan.

Equity Compensation Plans. St. Mary has the Equity Plan under which options and shares of St. Mary 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, 2009:

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)	1,274,920	$ 13.31	-
Restricted stock (1)	408,356	-	-
Performance share awards (1)(3)	1,145,871	$ 32.52	1,771,009
Total for Equity Incentive Compensation Plan	2,829,147	$ 22.40	1,771,009
Employee Stock Purchase Plan (2)	-	-	1,468,275
Equity compensation plans not approved by security holders	-	-	-
Total for all plans	2,829,147	$ 22.40	3,239,284

(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, and stock-based awards to key employees, consultants, and members of the Board of Directors of St. Mary or any affiliate of St. Mary. 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 out of 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 on March 26, 2008, and the amended plan was approved by stockholders at our annual stockholders' meeting May 21, 2008. Our Board of Directors approved additional amendments to the Equity Plan on March 26, 2009, and the amendments were approved by stockholders at our annual stockholders' meeting on May 20, 2009. Awards granted in 2009, 2008, and 2007 under the Equity Plan were 1,016,931, 932,767, and 135,138, respectively.

(2) Under the St. Mary Land & Exploration 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 86,308, 45,228, and 29,534 in 2009, 2008, and 2007, 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 cumulative Total Shareholder Return ("TSR") for the performance period and the relative measure of our TSR compared with the TSR an index comprised of certain peer companies for the performance period. The current outstanding PSAs were granted on August 1, 2009, and 2008, and utilize a three-year performance measurement period which began on July 1, 2009, and 2008, respectively. 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 $32.52 price shown in the above table represents the weighted-average per share fair value as of December 31, 2009, calculated pursuant to ASC Topic 718, which is presented in order to provide additional information regarding the potential dilutive effect of the PSAs as of December 31, 2009, 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.

Issuer Purchases of Equity Securities. The following table provides information about purchases by the Company or "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the quarters and year ended December 31, 2009, 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.

PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS

	Total Number of Shares Purchased (1)(2)(3)(4)	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(5)
January 1, 2009 – March 31, 2009	58,688	$ 13.60	-0-	3,072,184
April 1, 2009 - June 30, 2009	341	$ 18.69	-0-	3,072,184
July 1, 2009 - September 30, 2009	412	$ 24.86	-0-	3,072,184
October 1, 2009 - October 31, 2009	30	$ 35.36	-0-	3,072,184
November 1, 2009 - November 30, 2009	86	$ 34.10	-0-	3,072,184
December 1, 2009 - December 31, 2009	21,391	$ 35.34	-0-	3,072,184
Total October 1, 2009 - December 31, 2009	21,507	$ 35.33	-0-	3,072,184
Total	80,948	$ 19.45	-0-	3,072,184

(1) Includes a total of 6,500 shares purchased by Anthony J. Best, St. Mary's President and Chief Executive Officer, in open market transactions that were not made pursuant to our stock repurchase program.

(2) Includes a total of 5,000 shares purchased by A. Wade Pursell, St. Mary's Executive Vice President and Chief Financial Officer, in open market transactions that were not made pursuant to our stock repurchase program.

(3) Includes a total of 10,000 shares purchased by William D. Sullivan, a Director of St. Mary, in open market transactions that were not made pursuant to our stock repurchase program.

(4) Includes 59,448 shares withheld (under the terms of grants under the Equity Incentive Compensation Plan) to offset tax withholding obligations that occur upon the delivery of

outstanding shares underlying restricted stock units that were not made pursuant to our stock repurchase program.

(5) 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 have Board authorization to repurchase 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 St. Mary's existing bank credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under St. Mary's bank credit facility. The stock repurchase program may be suspended or discontinued at any time.

The payment of dividends and stock repurchases are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation that does not allow our annual dividend rate to exceed $0.25 per share.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth supplemental selected financial and operating data for St. Mary 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 St. Mary. 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 St. Mary’s consolidated financial statements included in this report.

	Years Ended December 31,				
	2009	2008 (1)	2007(1)	2006	2005
	(In thousands, except per share data)				
Total operating revenues	$ 832,201	$ 1,301,301	$ 990,094	$ 787,701	$ 739,590
Net income (loss)	$ (99,370)	$ 87,348	$ 187,098	$ 190,015	$ 151,936
Net income (loss) per share:					
Basic	$ (1.59)	$ 1.40	$ 3.02	$ 3.38	$ 2.67
Diluted	$ (1.59)	$ 1.38	$ 2.90	$ 2.94	$ 2.33
Total assets at year end	$ 2,360,936	$ 2,697,247	$ 2,572,942	$ 1,899,097	$ 1,268,747
Long-term obligations:					
Line of credit	$ 188,000	$ 300,000	$ 285,000	$ 334,000	$ -
Senior convertible notes, net of debt discount	$ 266,902	$ 258,713	$ 251,070	$ 99,980	$ 99,885
Cash dividends declared and paid per common share	$ 0.10	$ 0.10	$ 0.10	$ 0.10	$ 0.10

(1) As Adjusted, see Note 5 to the Consolidated Financial Statements

Supplemental Selected Financial and Operations Data

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share data)				
Balance Sheet Data					
Total working capital (deficit)	$ (87,625)	$ 15,193	$ (92,604)	$ 22,870	$ 4,937
Total stockholders' equity	$ 973,570	$ 1,162,509	$ 902,574	$ 743,374	$ 569,320
Weighted-average shares outstanding					
Basic	62,457	62,243	61,852	56,291	56,907
Diluted	62,457	63,133	64,850	65,962	66,894
Reserves					
Oil (MMBbl)	53.8	51.4	78.8	74.2	62.9
Gas (Mcf)	449.5	557.4	613.5	482.5	417.1
MCFE	772.2	865.5	1,086.5	927.6	794.5
Production and Operational:					
Oil and gas production revenues, including hedging	$ 756,601	$ 1,158,304	$ 936,577	$ 758,913	$ 711,005
Oil and gas production expenses	$ 206,800	$ 271,355	$ 218,208	$ 176,590	$ 142,873
DD&A	$ 304,201	$ 314,330	$ 227,596	$ 154,522	$ 132,758
General and administrative	$ 76,036	$ 79,503	$ 60,149	$ 38,873	$ 32,756
Production Volumes:					
Oil (MMBbl)	6.3	6.6	6.9	6.1	5.9
Gas (Bcf)	71.1	74.9	66.1	56.4	51.8
BCFE	109.1	114.6	107.5	92.8	87.4
Realized price – pre hedging:					
Per Bbl	$ 54.40	$ 92.99	$ 67.56	$ 59.33	$ 53.18
Per Mcf	$ 3.82	$ 8.60	$ 6.74	$ 6.58	$ 8.08
Realized price – net of hedging:					
Per Bbl	$ 56.74	$ 75.59	$ 62.60	$ 56.60	$ 50.93
Per Mcf	$ 5.59	$ 8.79	$ 7.63	$ 7.37	$ 7.90
Expense per MCFE:					
LOE	$ 1.33	$ 1.46	$ 1.31	$ 1.25	$ 0.99

Transportation	$ 0.19	$ 0.19	$ 0.14	$ 0.12	$ 0.09
Production taxes	$ 0.37	$ 0.71	$ 0.58	$ 0.54	$ 0.56
DD&A	$ 2.79	$ 2.74	$ 2.12	$ 1.67	$ 1.52
General and administrative	$ 0.70	$ 0.69	$ 0.56	$ 0.42	$ 0.37
Cash Flow:					
Provided by operations	$ 436,106	$ 679,190	$ 632,054	$ 467,700	$ 409,379
Used in investing	$ (304,092)	$ (673,754)	$ (805,134)	$ (724,719)	$ (339,779)
Provided by (used in) financing	$ (127,496)	$ (42,815)	$ 215,126	$ 243,558	$ (61,093)

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

This discussion includes forward-looking statements. Please refer to "Cautionary Information about Forward-Looking Statements" in Part I, Items 1 and 2 of this Form 10-K for important information about these types of statements.

Overview of the Company

General Overview

We are an independent energy company focused on the development, exploration, exploitation, acquisition, and production of natural gas and crude oil in North America. We generate nearly all our revenues and cash flows from the sale of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated primarily in the Rocky Mountain Williston Basin; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the productive formations of East Texas and North Louisiana; north central Pennsylvania; the Maverick Basin in South Texas; and the onshore Gulf Coast and offshore Gulf of Mexico. We have developed a balanced and diverse portfolio of proved reserves, development drilling opportunities, and unconventional resource prospects.

Our mission is to deliver outstanding net asset value per share growth to our investors via attractive oil and gas investments. Historically, we have relied on a strategy of growing through niche acquisitions focused in the continental United States. Over the last few years, we have shifted our strategy to focus more on capturing potential resource plays earlier and at a lower cost. We believe that this shift will allow for more stable and predictable production and proved reserves growth. Going forward, we will focus on continuing to acquire significant leasehold positions in existing and emerging resource plays in North America.

In 2009 we had the following financial and operational results:

- Average daily gas production of 194.8 MMcf was down five percent from 2008. Average daily oil production of 17.3 MBbl was down four percent from 2008. Average total equivalent daily production was 298.8 MMCFE, which was down five percent from 2008.

- Estimated proved reserves of 53.8 MMBbls of oil and 449.5 Bcf of natural gas, or 772.2 BCFE, as of December 31, 2009. This was a decrease of 11 percent from year-end 2008 proved reserves of 865.5 BCFE and reflects the divestiture of 44.2 BCFE of non-strategic properties, 61.6 BCFE in net downward performance revisions, and 12.0 BCFE of net positive price revisions. We had reserve additions from extensions and discoveries and infill drilling of 109.6 BCFE.

- We recorded a net loss of $99.4 million and diluted loss per share of $1.59 for the year ended December 31, 2009. This compares with net income of $87.3 million, or $1.38 per diluted share, for the year ended December 31, 2008.

- Cash flow from operating activities of $436.1 million, a decrease of 36 percent from 2008.

- Costs incurred for oil and gas producing activities for the year ended December 31, 2009, were $419.0 million, compared with $857.7 million for the same period in 2008.

Our operations are generally funded first through cash flows from operating activities and then through borrowings under our existing credit facility. The divestiture of non-core 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 existing facility, property sales, and cash flow from operating activities. In 2009 we invested $377.2 million for development and exploration and $41.7 million for leasehold.

A major determination of the value of our company is the value of our proved reserves. At year-end 2009 we had proved reserves of 772.2 BCFE of which 58 percent were natural gas and 82 percent were characterized as proved developed. There were a number of changes that took effect in 2009 impacting the calculation of our year-end proved reserves. The SEC instituted a number of revisions to its existing oil and gas reporting requirements. A key revision to the rules pertains to the use of 12-month average pricing as opposed to year-end pricing in estimating proved reserves. The prices used in the calculation of proved reserve estimates as of December 31, 2009, were $61.18 per Bbl and $3.87 per MMBTU for oil and natural gas, respectively. These prices were 23 percent and 33 percent lower, respectively, than the year-end prices that would have been used under the SEC's previous methodology. Additional changes in the SEC rules provide for the use of new technology to determine proved reserves and the ability to include nontraditional resources in proved reserves. In addition to these regulatory changes, in 2009 we began recording estimates of proved reserve volumes for properties we believe are reasonably certain to generate positive net cash flows on an undiscounted basis, which we have the intent to drill, and which meet our internal economic criteria for drilling even though they may have a negative PV-10 value. Previously, we booked proved reserve volumes if the properties showed a positive PV-10 value, we had the intent to drill, and the wells met our economic criteria.

We added 109.6 BCFE from our drilling program during the year, with our emerging resource play in the Eagle Ford shale in the Maverick Basin in South Texas contributing a significant portion of those additions. Our programs targeting the Woodford shale in eastern Oklahoma and the Bakken/Three Forks formations in the North Dakota portion of the Williston Basin also added meaningful additions in 2009. We sold 44.2 BCFE of proved reserves during the year, with roughly 90 percent of those relating to the divestiture of our coalbed methane project at Hanging Woman Basin along the border of Montana and Wyoming. The balance of the divested properties sold in 2009 was non-strategic assets, which were spread across the company. We had a downward net revision of 49.6 BCFE that consisted of 61.6 BCFE in net downward engineering revisions and a net positive pricing revision of 12.0 BCFE. The largest portion of the performance revision relates to producing properties in our Wolfberry tight oil program in the Permian Basin in West Texas. Well performance data collected during 2009 for Wolfberry assets at Sweetie Peck and Halff East indicated these assets are underperforming our year-end 2008 decline forecasts. Accordingly, we removed roughly 37 BCFE from proved reserves in the Permian region, primarily related to the Wolfberry tight oil program. We believe that a significant portion of these reserves, while not meeting the criteria to be booked as proved reserves at year-end, are likely to be produced eventually. We also saw a downward performance revision of approximately 12 BCFE related to certain Cotton Valley assets in our ArkLaTex region. Due to the pricing methodology changes noted above, we recognized positive price revisions in our oil-weighted Rocky Mountain and Permian regions that offset negative price revisions we recognized in the natural gas weighted Mid-Continent, ArkLaTex, and South Texas & Gulf Coast regions. Under the previous methodology of using year-end pricing for the determination of proved reserves, we would have had an increase of four percent in proved reserves to approximately 897 BCFE.

The PV-10 value of our proved reserves was $1.3 billion as of December 31, 2009. The after tax value of $1.0 billion as represented by the standardized measure calculation is presented in Note 16 – Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report. A reconciliation between these two amounts is shown under Reserves in Part I, Items 1 and 2 of this report.

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 economically add reserves in excess of production.

The following table provides various reserve replacement and finding cost metrics for the year ended December 31, 2009:

	Reserve Replacement Percentage		Finding Cost per MCFE	
	Excluding sales	Including sales	Excluding sales	Including sales
Drilling, excluding revisions	100%	60%	$ 3.44	$ 5.77
Drilling, including revisions	55%	14%	$ 6.29	$ 23.91
Drilling and acquisitions, excluding revisions	100%	60%	$ 3.44	$ 5.77
Drilling and acquisitions, including revisions	55%	14%	$ 6.29	$ 23.92
Acquisitions	N/M	N/M	N/M	N/M
All-in	55%	14%	$ 6.99	$ 26.56

The following table provides three-year average reserve replacement and finding cost metrics for the years ended December 31, 2009, 2008, and 2007:

	Reserve Replacement Percentage		Finding Cost per MCFE	
	Excluding sales	Including sales	Excluding sales	Including sales
Drilling, excluding revisions	124%	92%	$ 4.27	$ 5.77
Drilling, including revisions	48%	16%	$ 11.07	$ 33.90
Drilling and acquisitions, excluding revisions	162%	129%	$ 3.68	$ 4.60
Drilling and acquisitions, including revisions	85%	53%	$ 6.97	$ 11.22
Acquisitions	37%	5%	$ 1.72	$ 12.60

All-in	85%	53%	$ 7.79	$ 12.53

Our 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 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 15 – Oil and Gas Activities and Note 16 – 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

During and subsequent to the third quarter of 2008, specific issues related to the financial sector rippled through the broader economy. The failure or takeovers of several large financial institutions adversely impacted the wider equity, debt, and credit markets. Financial strength and liquidity became increasingly important as investors considered the ability of companies to fund their planned levels of activity and to service their debt obligations. In addition, fears of prolonged weakness in the global economy leading to anemic energy demand resulted in a significant decline in oil and natural gas prices. As a result of these events, we entered 2009 with a business plan designed to operate within our operating cash flow. We have maintained a disciplined approach with our capital investments during the year, which, combined with higher operating cash flows than we anticipated originally, have allowed us to maintain our strong financial position and reduce borrowings under our credit facility. Our exploration and development program at the beginning of 2009 was designed to stay within generated cash flow. We met this goal in 2009. We continue to believe we have adequate liquidity available to us through our credit facility as discussed below under the caption Overview of Liquidity and Capital Resources.

Oil and Gas Prices

Our financial condition and the results of our operations are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. 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. Our crude oil is sold using contracts that pay us either the average of the NYMEX West Texas Intermediate daily settlement or the average of alternative posted prices for the periods in which the crude oil is produced, adjusted for quality, transportation, and location differentials. The following table is a summary of commodity price data for the years ended December 31, 2009, 2008, and 2007.

	For the Years Ended December 31,		
	2009	2008	2007
Crude Oil (per Bbl):			
Average NYMEX WTI spot price	$ 61.99	$ 99.92	$ 72.23
Realized price, before the effects of hedging	$ 54.40	$ 92.99	$ 67.56
Net realized price, including the effects of hedging	$ 56.74	$ 75.59	$ 62.60
Natural Gas (per Mcf):			
Average NYMEX Henry Hub spot price	$ 3.94	$ 8.89	$ 6.97
Realized price, before the effects of hedging	$ 3.82	$ 8.60	$ 6.74
Net realized price, including the effects of hedging	$ 5.59	$ 8.79	$ 7.63

We expect future prices for oil and natural gas to be volatile. The comparative strength of the U.S. Dollar will likely continue to impact crude prices just as changes in domestic industrial demand will continue to impact the price of natural gas. The 12-month strip prices for NYMEX WTI crude and NYMEX Henry Hub gas as of December 31, 2009, were $82.15 per Bbl and $5.87 per MMBTU, respectively; comparable prices as of February 16, 2010, were $79.43 per Bbl and $5.76 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 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, 2009, our net natural gas price realization was positively impacted by $125.9 million of realized hedge settlements and our net oil price realization was positively impacted by $14.8 million of realized hedge settlements.

Hedging Activities

Hedging is an important part of our financial risk management program. We have a Board-authorized financial risk management policy that governs our practices related 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.

We attempt to qualify our oil and gas derivative instruments as cash flow hedges for accounting purposes under Accounting Standards Codification Topic 815. Changes in the value of our hedge positions are primarily reflected in our consolidated balance sheets. A portion of the change in the value of our hedge positions is recognized in our consolidated statements of operations due to the hedges being partially ineffective. We recognized a $20.5 million in non-cash derivative loss for the year ended December 31, 2009.

The U.S. Congress is currently considering recent proposals to increase the regulatory oversight of the over-the-counter derivatives markets in order to promote more transparency in those markets. Although we cannot predict the ultimate outcome of these proposals, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and otherwise manage our financial risks related to swings in oil and gas commodity prices.

2009 Highlights

Developments in emerging resource plays. During 2008, the Haynesville shale, the Eagle Ford shale, and the Marcellus shale resource plays emerged as significant new sources of gas supply for the exploration and production industry. We have exposure to each of these plays that, if successful, could provide for significant future organic growth in reserves and production. The Haynesville shale emerged early in 2008 in northern Louisiana and eastern Texas and quickly became the most active resource play in the country. Our position was built as a result of prior leasing activity targeting the James Lime and Cotton Valley formations. Our Eagle Ford shale position in the Maverick Basin in South Texas was built from 2007 through 2009 through a combination of property acquisitions, leasing activity, and participation in a joint venture with industry partners. Late in 2008 we entered into arrangements that allow us to earn or purchase acreage in the Marcellus shale in north central Pennsylvania. During 2009 we worked to advance our understanding of these plays and move them closer to development mode. The most progress was made in our Eagle Ford shale program in South Texas. We successfully tested seven wells across our operated acreage position during the second half of 2009. The early results from this program suggest wells at the southern end of our acreage will produce drier gas while wells drilled further north will produce higher BTU-content gas and some condensate. We are currently booking only the parallel offsets to producing wells as proved undeveloped locations. As a result, we believe meaningful potential exists to grow proved reserves on our operated acreage with our planned drilling activity for 2010 and increased understanding of how reliable technology will allow the play to be developed. On our joint venture acreage in Dimmit County, Texas, we believe these wells will produce even higher amounts of condensate and oil compared to our operated position. In the Haynesville shale program in the ArkLaTex region, a number of successful wells were drilled around our acreage position in East Texas in 2009. We began horizontal drilling early in 2010 when our 3D seismic analysis was completed. In our Marcellus shale program in north central Pennsylvania, we drilled and completed our first two horizontal wells during 2009. Initial indications from the well tests were encouraging. The gathering line that will connect these wells to sales is in the process of being constructed.

Shift toward oil-weighted projects. As a result of continued downward pressure on natural gas prices and an increase in oil prices, we began shifting capital investment dollars toward oil-weighted projects during the third quarter. We saw an increase in activity in our Permian and Rocky Mountain regions as a result of this shift in capital.

Borrowing base on credit facility maintained. On September 29, 2009, the borrowing base on our credit facility was redetermined and maintained by our bank group at a value of $900 million.

Impairments. We recognized a pre-tax non-cash impairment of proved properties in the amount of $174.8 million in 2009. There was an impairment of proved properties in the amount of $302.2 million in 2008. A significant decrease in the market price for natural gas, including differentials in effect at March 31, 2009, caused the majority of the non-cash impairment. The largest portion of the change in 2009 was $97.3 million related to assets located in the Mid-Continent region which were impacted by the lower March 31, 2009, prices referred to above as well as wider than normal differentials. The ArkLaTex region was impacted by a $20.4 million impairment related to downward 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 for which we are relinquishing our ownership interests.

During the year, we abandoned or impaired $45.4 million related to unproved properties. The largest specific components of the 2009 impairment and abandonment related to the Floyd Shale acreage located in Mississippi and acreage in Oklahoma. The remaining write-offs were related to acreage we believe we will not be able to hold due to current allocations of capital and to acreage that we do not believe will be prospective.

Lastly, we incurred inventory write-downs of $14.2 million for the year ended December 31, 2009 in order to present inventory at the lower of cost or market value. The market value of tubular goods and other inventory items that were purchased in 2008 when prices for these goods were considerably higher declined over the course of 2009 as a result of lower levels of activity throughout the industry.

Divestitures. We continue to optimize our portfolio of assets as part of our overall strategy to focus on concentrated resource plays. As part of this strategy, on December 18, 2009, we completed the divestiture of our non-strategic coalbed methane project at Hanging Woman Basin located in the Rocky Mountain region. Total cash received was $23.3 million, which is subject to customary post-closing adjustments. During 2009 we recorded an $11.4 million gain on divestiture activity, which included the gain from the Hanging Woman Basin divestiture, as well as other smaller divestitures.

Production results. The table below details the regional breakdown of our 2009 production.

	ArkLaTex	Mid-Continent	South Texas & Gulf Coast	Permian	Rocky Mountain	Total(1)
2009 Production:						
Oil (MBbl)	124	274	407	1,845	3,678	6,328
Gas (MMcf)	14,167	34,380	7,255	4,075	11,229	71,106
Equivalent (MMCFE)	14,912	36,026	9,696	15,148	33,295	109,077
Avg. Daily Equivalents (MMCFE/per day)	40.8	98.7	26.6	41.5	91.2	298.8
Relative percentage	14%	33%	9%	14%	30%	100%

(1) Totals may not add due to rounding

In 2009 our production and oil and gas production revenues have outperformed our initial budget for 2009 due to stronger than anticipated production results from our Mid-Continent and Permian regions. Please refer to Comparison of Financial Results and Trends between 2009 and 2008 below for additional discussion on production.

Net Profits Plan. For the year ended December 31, 2009, the change in the value of this liability resulted in a non-cash benefit of $7.1 million compared with a $34.0 million benefit for the same period in 2008. Decreases in oil and gas commodity prices 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 from the Net Profits Plan have been expensed as compensation costs in the amounts of $19.9 million, $36.3 million, and $31.9 million for the years ended December 31, 2009, 2008, and 2007, respectively. Additionally, we accrued cash payments under the Net Profits Plan of $724,000 for the year ended December 31, 2009, as a result of sales proceeds during the fourth quarter of 2009. For the year ended December 31, 2008, we accrued for cash payments under the Net Profits Plan of $15.1 million as a result of sales proceeds from the Abraxas and Greater Green River Basin divestitures. These cash payments are accounted for as a reduction in the gain (loss) on divestiture activity in the accompanying consolidated statements of operations. There were no significant cash payments made or accrued for under the Net Profits Plan as a result of divestitures during 2007.

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 sections 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 now 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 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, 2009, would differ by approximately $14 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $9 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $8 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. In 2009 we made adjustments to the discount rate used for Net Profits Plan pools not in payout. Additionally, we changed the price assumption used for estimating the liability from a 36-month combination of historical and future prices to one using NYMEX strip prices at the end of the respective period.

Outlook for 2010

The general economic outlook for the country has improved compared to this time a year ago. We successfully weathered a tough 2009, and in the process advanced a number of potential resource plays and improved our financial condition.

As we enter 2010, we are well positioned both financially and operationally. Early in 2009, we extended the maturity of our revolving credit facility and subsequently paid down outstanding borrowings on that facility during the year. At the end of 2009, we had almost $500 million available under the revolving credit facility. We have no debt maturities until 2012. Additionally, we believe access to the capital markets has improved significantly since last year and that we could access capital through the public markets if necessary. From an operational standpoint, we believe 2010 has the potential to be a promising year for us. We will be building upon our successful testing programs from 2009. We have moved the Eagle Ford shale program much closer to development mode, and it will receive the largest portion of our capital budget this year. We will also be allocating more capital toward oil and rich natural gas projects given their higher returns in the current

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environment. Specifically, we will be drilling more Wolfberry tight oil and Bakken/Three Forks wells in the Permian and Rocky Mountain regions, respectively. We recently began drilling horizontal wells in the Haynesville shale. We continue to monitor service costs as the recent uptick in industry activity threatens to push rates for the drilling and completion of wells higher than the levels we saw in 2009.

Financial Results of Operations and Additional Comparative Data

We recorded a net loss for the year ended December 31, 2009 of $99.4 million or $(1.59) per diluted share compared to 2008 results of net income of $87.3 million or $1.38 per diluted share.

The table below provides information regarding selected production and financial information for the quarter ended December 31, 2009, 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, 2009	September 30, 2009	June 30, 2009	March 31, 2009
	(In millions, except production sales data)			
Production (BCFE)	26.1	26.4	28.2	28.4
Oil and gas production revenue, excluding the effects of hedging	$ 187.6	$ 152.7	$ 145.3	$ 130.4
Realized oil and gas hedge gain	$ 13.4	$ 28.3	$ 43.3	$ 55.6
Gain (loss) on divestiture activity	$ 22.1	$ (11.3)	$ 1.3	$ (0.6)
Lease operating expense	$ 34.3	$ 34.3	$ 35.6	$ 41.2
Transportation costs	$ 5.2	$ 5.3	$ 4.6	$ 5.5
Production taxes	$ 13.3	$ 9.0	$ 9.3	$ 9.1
DD&A	$ 75.1	$ 67.0	$ 70.4	$ 91.7
Exploration	$ 13.4	$ 15.7	$ 19.5	$ 13.6
Impairment of proved properties	$ 21.6	$ 0.1	$ 6.0	$ 147.0
Abandonment and impairment of unproved properties	$ 25.2	$ 4.8	$ 11.6	$ 3.9
Impairment of materials inventory	$ 0.8	$ 2.1	$ 2.7	$ 8.6
General and administrative	$ 20.7	$ 20.8	$ 18.2	$ 16.4
Bad debt recovery	$ (5.2)	$ -	$ -	$ -
Change in Net Profits Plan liability	$ 7.0	$ 6.8	$ 2.4	$ (23.3)
Unrealized derivative (gain) loss	$ 3.2	$ 4.1	$ 11.3	$ 1.8
Net income (loss)	$ 1.0	$ (4.4)	$ (8.3)	$ (87.6)
Percentage change from previous quarter:				
Production (BCFE)	(1)%	(6)%	(1)%	(5)%
Oil and gas production revenue, excluding the effects of hedging	23%	5%	11%	(32)%
Realized oil and gas hedge gain	(53)%	(35)%	(22)%	24%
Gain (loss) on divestiture activity	(296)%	(969)%	317%	(106)%
Lease operating expense	-%	(4)%	(14)%	(14)%
Transportation costs	(2)%	15%	(16)%	(10)%
Production taxes	48%	(3)%	2%	(23)%
DD&A	12%	(5)%	(23)%	(4)%
Exploration	(15)%	(19)%	43%	(23)%
Impairment of proved properties	21,500%	(98)%	(96)%	(50)%
Abandonment and impairment of unproved properties	425%	(59)%	197%	(89)%
Impairment of materials inventory	(62)%	(22)%	(69)%	N/A

General and administrative	-%	14%	11%	32%
Bad debt recovery	N/A	N/A	N/A	N/A
Change in Net Profits Plan liability	3%	183%	(110)%	(71)%
Unrealized derivative (gain) loss	(22)%	(64)%	528%	(115)%
Net income (loss)	(123)%	(47)%	(91)%	(31)%

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Changes in production volumes, oil and gas production revenues, and costs reflect the cyclical and highly volatile nature of our industry. As a result of the effects of lower commodity prices, we have seen reduced activity among many exploration and production companies over the past year which has led to lower lease operating costs over the last two quarters. We believe that industry activity may be stabilizing to a point where these costs no longer have much room to decline further. Production taxes are largely dependent on the prices we receive for oil and natural gas. Depreciation, depletion, and amortization generally had been pressured upward in recent years as production related to properties acquired or developed in a higher cost environment became a larger percentage of our production mix. During 2009, we have seen our DD&A rate fluctuate as a result of impairments and changes to our underlying proved reserve volumes, both of which have been affected by the swings in commodity prices we have seen this year. Additionally, the accounting treatment for assets that are classified as assets held for sale also impacted our DD&A rate since properties held for sale are no longer depreciated. A portion of our general and administrative expense is tied to the net revenues we generate, 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.

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	
	2009	2008	2007	2009/2008	2008/2007
Total proved reserves					
Oil (MMBbl)	53.8	51.4	78.8		
Natural gas (Bcf)	449.5	557.4	613.5		
BCFE	772.2	865.5	1,086.5	(11)%	(20)%
Net production volumes					
Oil (MMBbl)	6.3	6.6	6.9		
Natural gas (Bcf)	71.1	74.9	66.1		
BCFE	109.1	114.6	107.5	(5)%	7%
Average daily production					
Oil (MBbl)	17.3	18.1	18.9		
Natural gas (MMcf)	194.8	204.7	181.0		
MMCFE	298.8	313.1	294.5	(5)%	6%
Oil & gas production revenues					
Oil production, including hedging	$ 359,075	$ 500,062	$ 432,375		
Gas production, including hedging	397,526	658,242	504,202		
Total	$ 756,601	$ 1,158,304	$ 936,577	(35)%	24%

Oil & gas production costs										
Lease operating expenses	$	145,463	$	167,384	$	140,389				
Transportation costs		20,657		22,205		15,529				
Production taxes		40,680		81,766		62,290				
Total	$	206,800	$	271,355	$	218,208		(24)%		24%
Average net realized sales price (1)										
Oil (per Bbl)	$	56.74	$	75.59	$	62.60		(25)%		21%
Natural gas (per Mcf)	$	5.59	$	8.79	$	7.63		(36)%		15%
Per MCFE data										
Average net realized price (1)	$	6.94	$	10.11	$	8.71		(31)%		16%
Lease operating expense		(1.33)		(1.46)		(1.31)		(9)%		11%
Transportation costs		(0.19)		(0.19)		(0.14)		-%		36%
Production taxes		(0.37)		(0.71)		(0.58)		(48)%		22%
General and administrative		(0.70)		(0.69)		(0.56)		1%		23%
Operating profit	$	4.35	$	7.06	$	6.12		(38)%		15%
Depletion, depreciation and amortization	$	2.79	$	2.74	$	2.12		2%		29%

(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. Volatility in commodity prices has impacted our operating margins. The decrease in our equivalent realized price for production has corresponded with the significant downward move in commodity prices over the last year. While our cost structure has improved over the past year, it has not moved to the same degree. Our operating profit of $4.35 per MCFE for the year ended December 31, 2009, decreased 38 percent from the $7.06 per MCFE we realized for the comparable period in 2008.

Average daily production for the year ended December 31, 2009, decreased to 298.8 MMCFE compared with 313.1 MMCFE for the same period in 2008. For the year ended December 31, 2009, our average net realized price decreased by $3.17 per MCFE to $6.94 per MCFE from the same period in 2008. Lower commodity prices were the principal driver of the decrease in 2009. Unit costs decreased for the year ended December 31, 2009, as lease operating expense decreased $0.13 per MCFE to $1.33 per MCFE and production taxes decreased $0.34 per MCFE to $0.37 per MCFE. Production taxes are highly correlated to commodity prices, and a portion of our general and administrative expense is linked to our profitability and cash flow. Transportation costs remained steady at $0.19 per MCFE for the years ended December 31, 2009, and 2008.

For the year ended December 31, 2009, depletion, depreciation, amortization, and asset retirement obligation accretion expense, increased $0.05 per MCFE to $2.79 per MCFE compared with the same period in 2008. The depletion, depreciation, and amortization increase is a result of a decrease in proved reserves used to calculate DD&A in the first quarter of 2009, please refer to additional DD&A discussion above. Exploration expense for the year ended December 31, 2009, was $62.2 million, which was four percent higher than the $60.1 million incurred during the comparable period in 2008. Geological and geophysical expense increased $6.0 million due to an increase in the amount spent for seismic analysis. Exploratory dry hole expense increased $1.0 million. These increases were offset by a $4.9 million decrease in exploration overhead due to a decrease in Net Profits Plan payments resulting from decreased oil and gas commodity prices.

Proved reserves decreased 11 percent to 772.2 BCFE at December 31, 2009, from 865.5 BCFE at December 31, 2008. Please see Note 16 – Disclosures about Oil and Gas Producing Activities of Part IV, Item 15 of this report and the above discussion under the caption General Overview for additional details and discussion on the individual components of the change. Over time, our ability to economically replace volumes produced annually has proven to be a key factor that determines whether we are successful in achieving our goal of increasing net asset value per share. The measure of our success will vary year-to-year due to changes in these factors.

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

	As of and for the Years Ended December 31,			Percent Change Between	
	2009	2008	2007	2009/2008	2008/2007
Working capital (deficit)	$ (87,625)	$ 15,193	$ (92,604)	(677)%	116%
Long-term debt	$ 454,902	$ 558,713	$ 536,070	(19)%	4%
Stockholders' equity	$ 973,570	$ 1,162,509	$ 902,574	(16)%	29%
Net income	$ (99,370)	$ 87,348	$ 187,098	(214)%	(53)%
Basic net income per common share	$ (1.59)	$ 1.40	$ 3.02	(214)%	(54)%
Diluted net income per common share	$ (1.59)	$ 1.38	$ 2.90	(215)%	(52)%

Basic weighted-average shares outstanding		62,457		62,243		61,852	-%	1%
Diluted weighted-average shares outstanding		62,457		63,133		64,850	(1)%	(3)%
Net cash provided by operating activities	$	436,106	$	679,190	$	632,054	(36)%	7%
Net cash used in investing activities	$	(304,092)	$	(673,754)	$	(805,134)	(55)%	(16)%
Net cash provided by (used in) financing activities	$	(127,496)	$	(42,815)	$	215,126	198%	(120)%

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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. We have in-the-money stock options, unvested RSUs, and PSAs that may be potentially dilutive securities. Both basic and diluted earnings per share are presented in the table above. There were no potentially dilutive shares related to in-the-money stock options, unvested RSUs, and 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. 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 2009, 2008, and 2007 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 189,740 shares of common stock in 2009, 868,372 shares in 2008, and 733,650 shares in 2007 as a result of stock option exercises. These share issuances were offset by the repurchase of 2,135,600 shares of common stock in 2008, and 792,216 shares in 2007 through our stock repurchase plan. Additionally, the number of RSUs that vested in 2009, 2008, and 2007 were 211,092, 291,659, and 268,123, respectively.

Additional Comparative Data in Tabular Format:

	Change Between Years	
Oil and Gas Production Revenues:	2009 and 2008	2008 and 2007
Increase (decrease) in oil and gas production revenues, net of hedging (in thousands)	$ (401,703)	$ 221,727

Components of Revenue Increases (Decreases):

Oil		
Realized price change per Bbl, net of hedging	$ (18.85)	$ 12.99
Realized price percent change	(25)%	21%
Production change (MBbl)	(287)	(292)
Production percentage change	(4)%	(4)%
Natural Gas		
	$ (3.20)	$ 1.16

Realized price change per Mcf, net of hedging		
Realized price percentage change	(36)%	15%
Production change (MMcf)	(3,804)	8,849
Production percentage change	(5)%	13%

Our product mix as a percentage of total oil and gas revenue and production:

	Years Ended December 31,		
Revenue	2009	2008	2007
Oil	47%	43%	46%
Natural Gas	53%	57%	54%
Production			
Oil	35%	35%	39%
Natural Gas	65%	65%	61%

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Information regarding the effects of oil and gas hedging activity:

	Years Ended December 31,		
	2009	2008	2007
Oil Hedging			
Percentage of oil production hedged	52%	61%	66%
Oil volumes hedged (MBbl)	3,306	4,022	4,565
Increase (Decrease) in oil revenue	$ $14.8 million	$ (115.1 million)	$ (34.3 million)
Average realized oil price per Bbl before hedging	$ 54.40	$ 92.99	$ 67.56
Average realized oil price per Bbl after hedging	$ 56.74	$ 75.59	$ 62.60
Natural Gas Hedging			
Percentage of gas production hedged	45%	46%	46%
Natural gas volumes hedged (MMBtu)	$ 34.3 million	$ 36.4 million	$ 32.5 million
Increase in gas revenue	$ 125.9 million	$ 14.0 million	$ 58.7 million
Average realized gas price per Mcf before hedging	$ 3.82	$ 8.60	$ 6.74
Average realized price per Mcf after hedging	$ 5.59	$ 8.79	$ 7.63

Information regarding the components of exploration expense:

	Years Ended December 31,		
Summary of Exploration Expense (in millions)	2009	2008	2007
Geological and geophysical expenses	$ 20.2	$ 14.2	$ 17.0
Exploratory dry holes	7.8	6.8	14.4
Overhead and other expenses	34.2	39.1	27.3
Total	$ 62.2	$ 60.1	$ 58.7

Comparison of Financial Results and Trends 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, includes approximately 5.1 BCFE related to non-core properties divested throughout 2009. Adjusting for divestitures of non-core 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

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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 is 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 is 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 ArkLaTex decrease is 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.

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. Please refer to our discussion above under the heading Oil and Gas Prices.

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. We expect that marketed gas system revenue and expense will continue to trend with increases and decreases in production and our price realizations before the impact of hedging.

Gain (loss) 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 is mainly related to the Hanging Woman Basin divestiture that closed in December of 2009, which is subject to normal post-closing adjustments and is expected to be finalized during the first quarter of 2010. The 2008 gain is mainly related to the Abraxas divestiture that closed in January 2008. We expect to continue to evaluate potential divestitures of non-strategic properties.

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 is 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. We expect production taxes to trend with commodity prices.

- A $0.11 decrease in recurring lease operating expense on a per MCFE basis is related to reductions in recurring LOE that stems 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 is 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 reflects lower total production volumes in 2009 compared to 2008. Our DD&A expense per MCFE decreased due to the significant decrease in our carrying value of our properties as a result of proved property impairments that we incurred in the fourth quarter of 2008 and the first quarter of 2009. Proved property impairments and changes in underlying proved reserve volumes will continue to be affected by the swings in commodity prices.

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 is 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. We anticipate that we will continue to acquire seismic data into 2010 in order to minimize risk with respect to the acreage in our emerging resource plays with the expectation that we can optimize their future development. 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. We expect payments made under the Net Profits Plan to trend with 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. The 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. 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 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 the Floyd Shale acreage located in Mississippi and acreage in Oklahoma. Additionally, we incurred write-offs related to acreage we believe we will not keep 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 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. 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 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. We expect payments made under the Net Profits Plan to trend with commodity prices.

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 had been 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 $34.0 million benefit for the same period in 2008. Significant decreases in oil and gas commodity prices 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. We expect the change in this liability to trend with commodity prices.

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 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 our discussion under the heading Oil and Gas Prices.

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 effects of individual components of our tax rate can vary between periods resulting in fluctuations. The effective rate change from 2008 primarily reflects 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 is $20.4 million compared to current income tax expense of $19.2 million in 2008. These amounts are 34 percent and 33 percent, respectively, of the total income tax benefit or expense for each period. Our 2009 current income tax benefit reflects creation of a net operating loss which we can carry back to one or more prior tax years to obtain a refund. In future years, creation of net operating losses may not create current tax benefits. During 2009 we observed with interest U.S. Congressional legislative activity relating to possible changes in taxation of our industry. If the proposed legislation, which would reduce or eliminate current tax deductions for intangible drilling costs, the domestic production activities deduction, and percentage depletion allowance passes, we would expect our effective tax rate and the cash tax portion of our income tax expense to increase in the year the legislation becomes effective.

Comparison of Financial Results and Trends between 2008 and 2007

Oil and gas production revenue. Production increased seven percent to 114.6 BCFE for the year ended December 31, 2008, compared with 107.5 BCFE for the year ended December 31, 2007. Production for the year ended December 31, 2007, includes approximately 6.8 BCFE related to non-core properties divested throughout 2008. 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 (In millions)
ArkLaTex	12.8	$ 76.1	$ 8.3
Mid-Continent	(2.8)	30.4	3.9
South Texas & Gulf Coast	10.8	75.4	17.5
Permian	8.5	85.6	11.5
Rocky Mountain	(10.7)	79.8	11.9
Total	18.6	$ 347.3	$ 53.1

We grew daily production by approximately 18.6 MMCFE during 2008 compared to 2007. The largest regional increase occurred in the ArkLaTex region as a result of the success in the Cotton Valley and James Lime programs. Production in the South Texas & Gulf Coast region increased as a result of two acquisitions of properties targeting the shallow Olmos gas formation that were made in the second half of 2007 as well as several successful offshore wells. The production growth in the Permian region was the result of continued development of the Wolfberry assets at Sweetie Peck and Halff East. The declines in production in the Mid-Continent and Rocky Mountain regions were the result of the divestiture of non-core properties in these regions, which resulted in a smaller production base for 2008.

Realized oil and gas hedge gain (loss). We recorded a realized hedge loss of $101.1 million for the year ended December 31, 2008, mainly related to settlements on oil hedges. For the year ended December 31, 2007, we recorded a realized hedge gain of $24.5 million mainly due to favorable settlements on natural gas hedges.

Marketed gas system revenue and expense. Marketed gas system revenue increased $32.2 million to $77.4 million for the year ended December 31, 2008, compared with $45.1 million for the comparable period of 2007. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $29.7 million to $72.2 million for the year ended December 31, 2008, compared with $42.5 million for the comparable period of 2007. The net margin has stayed consistent with historical performance.

Other revenue. Other revenues decreased $6.6 million to $2.1 million for the year ended December 31, 2008, compared with $8.7 million for 2007. The decrease was due primarily to a $5.2 million gain recognized in 2007 associated with a global insurance settlement attributed to Hurricane Rita.

Gain (loss) on divestiture activity. We recorded a gain on sale of proved properties of $63.6 million for the year ended December 31, 2008, mainly related to the Abraxas divestiture in January 2008.

Oil and gas production expense. Total production costs increased $53.1 million or 24 percent to $271.4 million for 2008, from $218.2 million in 2007. Total oil and gas production costs per MCFE increased $0.33 to $2.36 for 2008, compared with $2.03 for 2007. This increase was comprised of the following:

- A $0.05 increase in overall transportation cost on a per MCFE basis was driven by the addition of Olmos shallow gas assets in the Maverick Basin that were acquired in the fourth quarter of 2007, as well as wells completed in 2008 that had higher transportation costs

- A $0.13 increase in production taxes on a per MCFE basis due to the increase in realized prices between periods, particularly in the oil-weighted Rocky Mountain and Permian regions

- A $0.10 increase in recurring lease operating expense on a per MCFE basis was related to higher costs, particularly in oil-weighted regions, for items such as fuel and fluid disposal and an increase in the South Texas & Gulf Coast region due to wells acquired and developed in South Texas during the fourth quarter of 2007

- A $0.05 overall increase in workover lease operating expense on a per MCFE basis relating to workover charges in the Mid-Continent and South Texas & Gulf Coast regions.

Depletion, depreciation, amortization and asset retirement obligation liability accretion. DD&A increased $86.7 million, or 38 percent, to $314.3 million in 2008 compared with $227.6 million in 2007. DD&A expense per MCFE increased 29 percent to $2.74 in 2008 compared to $2.12 in 2007. This increase was due to a higher per unit rate associated with our acquisition and drilling costs in 2008 and 2007 caused by overall upward cost pressure in the industry in recent years. Additionally, this increase reflected the costs of production facilities in the offshore Gulf Coast that had increased significantly in recent years and that started impacting our DD&A rate as those projects begin production. The DD&A per MCFE rate was further affected by downward revisions of 244.2 BCFE of proved reserves due to pricing and performance between December 31, 2008, and December 31, 2007, causing a general increase in DD&A.

Exploration. Exploration expense increased $1.4 million or two percent to $60.1 million in 2008 compared with $58.7 million for 2007. The increase was due to a $2.8 million increase in drilling arrangements and a $9.0 million increase in exploration overhead. These increases were offset by a $2.8 million decrease in geological and geophysical expense as well as a $7.6 million decrease related to exploratory dry hole expense due to fewer and less expensive dry holes.

Impairment of proved properties. We recorded a $302.2 million impairment of proved oil and gas properties in 2008 compared to no impairment in 2007. This impairment was primarily due to downward price adjustments to reserves and declining performance for properties primarily located in the South Texas & Gulf Coast region, as well as for gas properties in the Rocky Mountain region.

Abandonment and impairment of unproved properties. During the year, we abandoned or impaired $39.0 million of unproved properties. Approximately $13.4 million related to acreage to which we had assigned value in 2007 acquisitions targeting the Olmos shallow gas formation. The remaining write-offs related to acreage that we believed we either would not be able to hold in the current period of limited capital availability or to acreage that we did not believe would 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.

General and administrative. General and administrative expenses increased $19.4 million or 32 percent to $79.5 million for 2008, compared with $60.1 million for 2007. G&A increased $0.13 to $0.69 per MCFE for 2008 compared to $0.56 per MCFE for the same period in 2007 as G&A grew at a faster rate than the seven percent increase in production. A significant increase in employee count resulted in an increase in base employee

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compensation, including taxes and benefits, of approximately $23.9 million between 2008 and 2007. A significant driver of this headcount increase had been the conversion from contract lease operators to internal lease operators.

An increase in 2008 oil and gas commodity prices triggered additional Net Profits Plan payments. Additionally, an increased percentage of the distribution dollars under the Net Profits Plan associated with general and administrative expense contributed to a $4.4 million increase in the current period realized expense in 2008 compared with the same period in 2007.

Cash bonus and long-term incentive compensation expense increased by $8.4 million for the year ended December 31, 2008, compared with the same period in 2007. The increase resulted from the application of the Cash Bonus Plan as amended on March 28, 2008 and an increase in our employee count.

The amounts described above were offset by a $9.1 million increase in the amount of G&A that was allocated to exploration expense and an $8.2 million increase in COPAS overhead reimbursements. Our COPAS overhead reimbursements from operations increased due to an increase in our operated well count from our drilling program.

Change in Net Profits Plan liability. For the year ended December 31, 2008, this non-cash item was a benefit of $34.0 million compared to an expense of $50.8 million for the same period in 2007. Significant decreases in oil and gas commodity prices during the last half of 2008 and payments out of the plan have decreased the estimated liability for the future amounts to be paid to plan participants.

Bad debt expense. 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.

Income tax benefit (expense). Income tax expense totaled $57.4 million for 2008 and $109.0 million for 2007, resulting in effective tax rates of 39.7 percent and 36.8 percent, respectively. The effective rate change from 2007 was primarily due to the impact of goodwill impairment, changes in the mix of the highest marginal state tax rates, and also reflects other permanent differences including differing estimated effects between years of the domestic production activities deduction.

Our current income tax expense in 2008 was $19.2 million compared to $17.6 million in 2007. These amounts were 33 percent and 16 percent of the total income tax expense for the respective periods.

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

Based on our current outlook, we expect our generated cash flow from operations in 2010 plus proceeds from our pending Rocky Mountain oil and other non-core asset divestiture packages to fund our exploration and development budget for 2010. Accordingly, we do not expect to access the capital markets in 2010. Throughout 2009, we identified and marketed non-core oil and gas properties. Net cash proceeds from transactions that closed in 2009, after commission costs, were $39.9 million. Subsequent to year end, we closed the Wyoming portion of our Rocky Mountain oil package and we plan to close the remaining North Dakota portion by the end of the first quarter of 2010. We anticipate 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 operating activities, use of our credit facility, sales of non-core properties, and access to capital markets. All of these sources 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 and natural gas, 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 sales of non-core producing properties. Historically, decreases in market prices have limited our industry's access to the capital markets. We believe the public debt markets are currently accessible. Equity and convertible debt issuances are also available to us as alternative financing sources. We do not anticipate the need to raise public debt or equity financing in the near term, however these are options we would consider under the appropriate circumstances. We intend to rely on our credit facility for borrowings.

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. On September 29, 2009, the lending group redetermined our reserve-backed borrowing base under the credit facility at $900 million. We have been provided a $678 million commitment amount by the bank group. The new amended credit facility agreement has a maturity date of July 31, 2012. Management believes that the current commitment is sufficient for our liquidity needs. To date, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than 16 percent of the lending commitments under the credit facility. We monitor the credit environment closely and have frequent discussions with the lending group.

As of February 16, 2010, we had $467.0 million of available borrowing capacity under this facility. Interest and commitment fees are accrued based on the borrowing base utilization percentage. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table located in Note 5 of Part IV, Item 15 of this report, and Alternate Base Rate loans accrue interest at Prime plus the applicable margin from the utilization table. Outstanding loans reduce the amount available under the commitment amount on a dollar-for-dollar basis, as do letters of credit. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties and a pledge of the common stock of our material subsidiary companies.

Our weighted-average interest rate paid in 2009 was 5.4 percent and included fees paid on the unused portion of the credit facility's aggregate commitment amount and amortization of deferred financing costs and the debt discount. We decreased our net borrowings from the previous year by $112.0 million when comparing the ending 2009 and 2008 balance sheet amounts. A decrease in the average outstanding credit facility balance throughout 2009, plus a decrease in interest rates, was offset by higher applicable margins, higher commitment fees on the unused portion of our credit facility and amortization of upfront financing costs and the 3.50% Senior Convertible Notes debt discount. This resulted in interest expense of $28.9 million in 2009 compared with $27.0 million in 2008.

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, 2009, our debt to EBITDA ratio and current ratio as defined by our credit agreement, were 1.10 and 2.75, respectively. We are in compliance with all covenants under this credit facility and expect to be in compliance for at least 12 months.

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.

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, and stockholder dividends. During 2009 we spent $379.3 million of cash on capital development and $76,000 of cash for property acquisitions. 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 revolving credit facility.

Expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of our capital resources. Our capital and exploration expenditures in 2010 will be funded with current year operating cash flows and proceeds from the divestiture of non-core assets. 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. Also the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities could 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.

As of the filing date of this report we have Board authorization 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 existing bank credit facility agreement, compliance with securities laws, and the terms and provisions of our stock repurchase program. There were no share repurchases in 2009.

Current proposals to fund the federal 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.

In 2009 we paid $6.2 million in dividends to our stockholders. Our intention is to continue to make these dividend payments for the foreseeable future subject to our future earnings, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise.

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	
	2009/2008	2008/2007	2009/2008	2008/2007
Net Cash Provided By (Used in) Operating Activities	$ (243,084)	$ 47,136	(36)%	7%
Net Cash Provided By Investing Activities	$ 369,662	$ 131,380	(55)%	(16)%

Net Cash Used In Financing Activities	$ (84,681)	$ (257,941)	198%	(120)%

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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 is $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 reflects 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. Current year proceeds received from the sale of oil and gas properties relate to non-core 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-core properties sold to Abraxas 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 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.

Analysis of cash flow changes between 2008 and 2007

Operating activities. Cash received from oil and gas production revenues, net of the realized effects of hedging, increased $265.2 million to $1.2 billion for the year ended December 31, 2008. The increase was the result of a seven percent increase in production and a 16 percent increase in our net realized price after hedging, resulting in a 24 percent increase in production revenue. Included in the oil and gas production revenue amounts was $101.1 million of net realized hedging losses. Net cash payments made for income taxes increased $18.5 million due to fluctuating oil and gas prices which increased our estimated quarterly income tax payments in 2008.

Investing activities. Total cash outflow for 2008 capital expenditures for leasehold and drilling activities increased $107.6 million or 17 percent to $746.6 million. Total cash outflow for 2008 related to the acquisition of oil and gas properties decreased $101.1 million or 55 percent to $81.8 million. Cash received from the sale of oil and gas properties increased $178.4 million and deposits to restricted cash increased $14.4 million for 2008 as compared to 2007.

Financing activities. Net repayments to our credit facility decreased $64.0 million for the year ended December 31, 2008, compared to 2007. We received $280.7 million less during 2008, compared to the same period in 2007, from the issuance of senior convertible debt. Our income tax benefit attributable to the exercise of stock awards increased $3.9 million to $13.9 million for the year ended December 31, 2008, compared with the same period in 2007. We received $1.9 million more proceeds from the sale of common stock in 2008, compared to 2007. Additionally, we invested $51.3 million more to repurchase shares of our common stock during 2008 compared to 2007.

We had $6.1 million in cash and cash equivalents and working capital of $15.2 million as of December 31, 2008, compared to $43.5 million in cash and cash equivalents and a working capital deficit of $92.6 million as of December 31, 2007.

Capital Expenditures

The following table sets forth certain historical information regarding the costs incurred by us in our oil and gas producing activities.

	For the Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Development costs	$ 223,108	$ 587,548	$ 592,275
Exploration costs	154,122	92,199	111,470
Acquisitions			
Proved properties	76	51,567	161,665
Unproved properties – acquisitions of proved properties (1)	-	43,274	23,495
Unproved properties - other	41,677	83,078	38,436
Total, including asset retirement obligations(2)(3)	$ 418,983	$ 857,666	$ 927,341

(1) Represents a portion of the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties. Refer to Note 3 – Acquisitions, Divestitures, and Assets Held for Sale in Part IV, Item 15 of this report for additional information.

(2) Includes capitalized interest of $1.9 million, $4.7 million, and $6.7 million for the years ended December 31 2009, 2008, and 2007, respectively.

(3) Includes amounts relating to estimated asset retirement obligations of $(805,000), $15.4 million, and $27.6 million for the years ended December 31 2009, 2008, and 2007, respectively.

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 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 $188.0 million of floating-rate debt outstanding as of December 31, 2009. Our fixed-rate debt outstanding, net of debt discount, at this same date was $266.9 million. As of December 31, 2009, we do not have any interest rate hedges in place to mitigate potential 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 borrowing base 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,		
	2009	2008	2007
	(In thousands)		
Oil	$ 29,523	$ 27,818	$ 25,248
Natural Gas	11,874	37,288	29,998
Total	$ 41,397	$ 65,106	$ 55,246

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, 2009, and through the date of this filing, our hedged positions of anticipated production through 2012 totaled approximately 6 million Bbls of oil, 63 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids.

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, 2009. 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 (Bbls)	Weighted-Average Contract Price (per Bbl)	Fair Value at December 31, 2009 Asset/(Liability) (in thousands)
First quarter 2010	468,000	$ 69.92	$ (4,777)
Second quarter 2010	426,000	$ 69.46	(5,180)
Third quarter 2010	393,000	$ 68.77	(5,513)
Fourth quarter 2010	309,000	$ 66.06	(5,457)
2011	1,164,000	$ 67.06	(20,977)
2012	1,051,400	$ 82.19	(5,503)
All oil swap contracts	3,811,400		$ (47,407)

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, 2009 Asset/(Liability) (in thousands)
First quarter 2010	337,500	$ 50.00	$ 64.91	$ (5,264)
Second quarter 2010	341,000	$ 50.00	$ 64.91	(6,198)
Third quarter 2010	344,500	$ 50.00	$ 64.91	(6,916)
Fourth quarter 2010	344,500	$ 50.00	$ 64.91	(7,378)
2011	1,236,000	$ 50.00	$ 63.70	(29,707)
All oil collars	2,603,500			$ (55,463)

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Gas Contracts

Gas Swaps			
Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at December 31, 2009 Asset/(Liability) (in thousands)
First quarter 2010			
IF ANR OK	160,000	$ 6.38	$ 136
IF CIG	210,000	$ 5.40	10
IF EL PASO	400,000	$ 6.94	587
IF HSC	2,270,000	$ 9.05	7,778
IF NGPL	460,000	$ 5.69	82
IF NNG VENTURA	380,000	$ 5.72	(60)
IF PEPL	410,000	$ 5.27	(102)
IF RELIANT	1,150,000	$ 5.33	(135)
IF TETCO STX	270,000	$ 5.66	28
NYMEX Henry Hub	990,000	$ 7.38	1,719
Second quarter 2010			
IF ANR OK	150,000	$ 5.31	(3)
IF CIG	200,000	$ 5.16	13
IF EL PASO	390,000	$ 6.00	264
IF HSC	1,870,000	$ 7.80	4,297
IF NGPL	430,000	$ 5.23	(31)
IF NNG VENTURA	360,000	$ 5.71	68
IF PEPL	170,000	$ 5.23	(9)
IF RELIANT	1,250,000	$ 5.10	(270)
IF TETCO STX	250,000	$ 5.64	45
NYMEX Henry Hub	960,000	$ 6.75	1,144
Third quarter 2010			
IF ANR OK	70,000	$ 5.64	6
IF CIG	240,000	$ 5.38	13
IF EL PASO	370,000	$ 6.33	264
IF HSC	1,350,000	$ 8.03	3,119
IF NGPL	500,000	$ 5.43	(47)
IF NNG VENTURA	360,000	$ 5.89	55
IF PEPL	230,000	$ 5.56	7
IF RELIANT	1,190,000	$ 5.37	(151)
IF TETCO STX	230,000	$ 5.81	37
NYMEX Henry Hub	960,000	$ 6.94	1,132
Fourth quarter 2010			
IF ANR OK	140,000	$ 5.97	4
IF CIG	270,000	$ 5.87	15
IF EL PASO	370,000	$ 6.43	190
IF HSC	590,000	$ 8.61	1,483

IF NGPL	430,000	$	5.61	(124	)
IF NNG VENTURA	360,000	$	6.34	24	
IF PEPL	520,000	$	5.92	23	
IF RELIANT	1,350,000	$	5.71	(219	)
IF TETCO STX	180,000	$	6.23	33	
NYMEX Henry Hub	840,000	$	7.52	1,083	

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Gas Swaps (continued)			
Contract Period	Volumes (MMBtu)	Weighted-Average Contract Price (per MMBtu)	Fair Value at December 31, 2009 Asset/(Liability) (in thousands)
2011			
IF ANR OK	500,000	$ 6.10	23
IF CIG	1,030,000	$ 5.96	217
IF EL PASO	1,780,000	$ 6.35	510
IF HSC	360,000	$ 9.01	859
IF NGPL	1,040,000	$ 6.09	42
IF NNG VENTURA	1,200,000	$ 6.36	34
IF PEPL	1,830,000	$ 6.04	39
IF RELIANT	4,510,000	$ 6.13	494
IF TETCO STX	1,420,000	$ 6.51	465
NYMEX Henry Hub	2,130,000	$ 6.72	909
2012			
IF ANR OK	360,000	$ 6.18	(11)
IF CIG	1,020,000	$ 5.77	(160)
IF EL PASO	850,000	$ 6.04	(139)
IF NGPL	660,000	$ 6.34	94
IF NNG VENTURA	620,000	$ 6.51	(35)
IF PEPL	2,730,000	$ 6.25	316
IF RELIANT	2,440,000	$ 6.22	9
IF TETCO STX	660,000	$ 6.30	(16)
All gas swap contracts	48,420,000		$ 26,158

Gas Collars				
Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2009 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in thousands)
First quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	$ 65
IF HSC	150,000	$ 5.57	$ 7.88	46
IF PEPL	1,230,000	$ 5.31	$ 7.61	302
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	27
Second quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	177
IF HSC	150,000	$ 5.57	$ 7.88	84
IF PEPL	1,235,000	$ 5.31	$ 7.61	639
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	49
Third quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	121
IF HSC	150,000	$ 5.57	$ 7.88	72
IF PEPL	1,240,000	$ 5.31	$ 7.61	518
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	46
Fourth quarter 2010				
IF CIG	510,000	$ 4.85	$ 7.08	(23)
IF HSC	150,000	$ 5.57	$ 7.88	38
IF PEPL	1,240,000	$ 5.31	$ 7.61	247
NYMEX Henry Hub	60,000	$ 6.00	$ 8.38	28
2011				
IF CIG	1,800,000	$ 5.00	$ 6.32	(360)
IF HSC	480,000	$ 5.57	$ 6.77	(63)
IF PEPL	4,225,000	$ 5.31	$ 6.51	(786)
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	15
All gas collars	14,450,000			$ 1,242

Natural Gas Liquid Contracts

Natural Gas Liquid Swaps	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2009 Asset/(Liability)
	(approx. Bbls)	(per Bbl)	(in thousands)
First quarter 2010	206,000	$ 46.73	$ (770)
Second quarter 2010	191,000	$ 46.28	(364)
Third quarter 2010	179,000	$ 46.20	(339)
Fourth quarter 2010	169,000	$ 46.16	(424)
2011	480,000	$ 43.20	(2,334)
2012	214,000	$ 43.70	(1,181)
All natural gas liquid swaps	1,439,000		$ (5,412)

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	$ 498.2	$ 10.1	$ 488.1	$ -	$ -
Operating Leases	61.1	27.8	9.7	5.3	18.3
Other Long-Term Liabilities	302.8	92.1	125.1	59.9	25.7
Total	$ 862.1	$ 130.0	$ 622.9	$ 65.2	$ 44.0

This table includes the remaining unfunded portion of our estimated pension liability of $9.5 million even though we recognize that we cannot determine with accuracy the timing of future payments. The Company is not required to make a contribution to the Pension Plan in 2010. We made contributions of $2.0 million, $2.5 million, and $2.2 million in 2009, 2008, and 2007, respectively, towards the pension liability. The table also includes $166.1 million in other long-term liabilities that represents six years of undiscounted forecasted payments for the Net Profits Plan. Payments are expected to be similar on an annual basis 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 scheduled repayment of the long-term credit facility is 2012. Accordingly, it has been disclosed in the table as such. Since this is a revolving credit facility, the actual payments will vary significantly. We anticipate refinancing this obligation prior to its expiration date. For purposes of this table, we assume we will net share settle the 3.50% Senior Convertible Notes. Accordingly, $22.7 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 $119.4 million based on future market prices as of December 31, 2009. This amount represents only the cash outflows; it does not include estimated oil and gas derivative receipts of $38.0 million that would be paid based on December 31, 2009, market prices. The net liability of $81.4 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, 2009, was a net liability of $80.9 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.

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, 2009, 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 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 16 – 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 required by Accounting Standards Codification Topic 932

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Extractive Activities – Oil and Gas requires 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 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,		
	2009	2008	2007
	BCFE Change	BCFE Change	BCFE Change
Revisions resulting from price changes	12.0	(199.7)	34.5
Revisions resulting from performance	(61.6)	(44.5)	6.4
Total	(49.6)	(244.2)	40.9

We have added 282.8 BCFE of reserves over a three-year period, excluding divestitures. A 99.7 BCFE decrease in reserves was a result of changes in engineering estimates based on the performance of our oil and gas properties. A 153.2 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,					
	2009		2008		2007	
	BCFE Change	Percentage Change	BCFE Change	Percentage Change	BCFE Change	Percentage Change
A 10% decrease in pricing	(25.1)	(3)%	(120.8)	(14)%	(16.3)	(2)%
A 10% decrease in proved undeveloped reserves	(14.2)	(2)%	(15.0)	(2)%	(25.0)	(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 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 $8 million in 2009.

Crude oil and natural gas hedging. Our crude oil and natural gas hedging contracts are intended to and usually do qualify for cash flow deferral hedge accounting under Accounting Standards Codification Topic 815. Under this guidance a majority of the gain or loss from a contract qualifying as a cash flow hedge is deferred from recognition in the consolidated statement of operations. The realized gain or loss reflected in the consolidated statement of operations is based on actual hedge contract settlements. If our natural gas and crude oil hedge contracts did not qualify for hedge accounting treatment or if we chose not to use hedge accounting methodology, 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 $103.3 million of loss, $223.5 million of income, and $170.0 million of loss for 2009, 2008, and 2007, respectively, would have increased or decreased net income after tax if our hedges did not qualify as cash flow deferral hedges under Accounting Standards Codification Topic 815.

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 Overview of the Company, under the heading Net Profits Plan. In December 2007 our Board approved an incentive compensation plan restructuring whereby the Net Profits Plan was replaced with a long-term incentive program utilizing performance shares. 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 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

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assumptions or discount rates could result in a different calculated impairment. We recorded a $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 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 in accordance with Accounting Standards Codification Topic 740. 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 determining 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 benefit by $675,000 for the year ended December 31, 2009.

Other Liquidity and Capital Resources Information

Pension Benefits

Substantially all of our employees who meet age and service requirements participate in a non-contributory defined benefit pension plan. At December 31, 2009, and 2008, our underfunded status was $9.4 million and $8.2 million, respectively. The increase in underfunding from 2008 to 2009 was primarily attributable to lower discount rates, which were 6.6 percent in 2008 and 6.1 percent in 2009. Our pension plan assets increased from $6.6 million at December 31, 2008, to $9.1 million at December 31, 2009. On an Employee Retirement Income Security Act basis, the Company's pension plan remains fully funded at January 1, 2010. We are not required to make any contributions to the pension plan in 2010. For additional information please refer to Note 8 – Pension Benefits in Part IV, Item 15 of this report.

Accounting Matters

Please refer to Note 5 – Long-term Debt, Note 8 – Pension Benefits, Note 10 - Derivative Financial Instruments, Note 11 – Fair Value Measurements, Note 16 – Disclosures about Oil and Gas Producing Activities, and 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

St. Mary's compliance with applicable environmental 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 regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, 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.

The U.S. Congress is currently considering legislation that would amend the Safe Drinking Water Act to eliminate an existing exemption from federal regulation of hydraulic fracturing activities. Hydraulic fracturing is a common process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable oil or natural gas to move more easily through the rock pores to a production well. This process is often necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing in many of our reservoirs, and our Eagle Ford, Haynesville, Marcellus, and Woodford shale programs utilize or contemplate the utilization of hydraulic fracturing. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. If adopted, the proposed amendment to the Safe Drinking Water Act could result in additional regulations and permitting requirements at the federal level. Those additional regulations and permitting requirements, as well as other regulatory developments at the state level, could lead to significant operational delays and increased operating costs, and could make it more difficult to perform hydraulic fracturing.

Climate Change

Climate change has become the subject of an important public policy debate. While climate change remains a complex issue, scientific research suggests that an increase in greenhouse gas emissions may pose a risk to society and the environment. The oil and natural gas exploration and production industry is a source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting of natural gas could have a significant impact on our future operations. We are actively monitoring the following climate change related issues:

Impact of Legislation and Regulation. The commercial risk associated with the exploration and production of fossil fuels lies in the uncertainty of government-imposed climate change legislation, including cap and trade systems, and regulations that may affect us, our suppliers, and our customers. The cost of meeting these requirements may have an adverse impact on our financial condition, results of operations and cash flows, and could reduce the demand for the oil and natural gas that we produce. The U.S. Congress and several states are considering adopting climate change legislation. However, the current state of development of many state and federal climate change regulatory initiatives makes it difficult to predict with certainty the future impact on us, including accurately estimating the related compliance costs that we may incur.

Impact of U.S. Participation in International Accords. The U.S. has participated in international discussions to develop a treaty or other agreement to require reductions in greenhouse gas emissions after 2012, and has indicated that it wishes to associate itself with the Copenhagen Accord, which includes a non-binding commitment to reduce greenhouse gas emissions. While no specific new international climate change accord has been adopted that would affect our current operating locations, the current state of development of many initiatives makes it difficult to assess the timing or effect of any pending discussions of future accords or predict with certainty the future costs that we may incur in order to comply with any applicable requirements from future international treaties or regulations.

Indirect Consequences of Regulation or Business Trends. We believe that there are both risks and opportunities arising from climate change issues. See Items 1 and 2. Business and Properties – Government Regulations, and the following risk factors listed in Item 1A. Risk Factors –

- We are subject to operating and environmental risks and hazards that could result in substantial losses.
- Our operations are subject to complex laws and regulations, including environmental regulations that result in substantial costs and other risks.
- Possible legislation and regulations related to global warming and climate change could have an adverse effect on our operations and the demand for oil and natural gas.

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

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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. More than 60% of our 2009 production on an MCFE basis was natural gas. 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.

Physical Impacts of Climate Change on our Costs and Operations. There has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Extreme weather conditions can increase our costs, and damage resulting from extreme weather may not be fully insured. However, the extent to which climate change may lead to increased storm or weather hazards affecting our operations is difficult to identify at this time. See Item 1A. Risk Factors – We are subject to operating and environmental risks and hazards that could result in substantial losses.

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," "Summary of Oil and Gas Production Hedges in Place," and "Summary of Interest Rate 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 the 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 St. Mary Land & Exploration 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, 2009. 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, 2009.

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	/s/ A. WADE PURSELL
Anthony J. Best	A. Wade Pursell
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer
February 23, 2010	February 23, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
St. Mary Land & Exploration Company and Subsidiaries
Denver, Colorado

We have audited the internal control over financial reporting of St. Mary Land & Exploration Company and subsidiaries (the "Company") as of December 31, 2009, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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, 2009, 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, 2009, of the Company and our report dated February 23, 2010, expressed an unqualified opinion on those financial statements and included explanatory paragraphs regarding the Company's adoption of new accounting standards.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2010

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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 St. Mary'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 St. Mary's definitive proxy statement for the 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009. The information required by the Item concerning St. Mary's executive officers is incorporated by reference to the information provided in Part I – Item 4A – 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 St. Mary's definitive proxy statement for the 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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 St. Mary's definitive proxy statement for the 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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 St. Mary's definitive proxy statement for the 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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 Form 10-K.

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 St. Mary's definitive proxy statement for the 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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 St. Mary's definitive proxy statement for the 2010 annual meeting of stockholders to be filed within 120 days from December 31, 2009.

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 November 1, 2006, among Henry Petroleum LP, Henry Holding LP, Henry Group, Entre Energy Partners LP, and St. Mary Land & Exploration Company (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on December 18, 2006, and incorporated herein by reference)
2.2	Purchase and Sale Agreement dated August 2, 2007, among Rockford Energy Partners II, LLC and St. Mary Land & Exploration Company (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K filed on October 5, 2007, and incorporated herein by reference)
2.3	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)
2.4	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)
2.5*	

	Purchase and Sale Agreement dated December 17, 2009 and effective as of November 1, 2009, between Legacy Reserves Operating LP and St. Mary Land and Exploration Company
2.6*	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 and Exploration Company

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Exhibit Number	Description
3.1	Restated Certificate of Incorporation of St. Mary Land & Exploration Company as amended on May 25, 2005 (filed as Exhibit 3.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference)
3.2	Restated By-Laws of St. Mary Land & Exploration Company amended as of December 18, 2008 (filed as Exhibit 3.1 to the registrant's Current Report on Form 8-K filed on December 23, 2008, 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)
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†	Cash Bonus Plan (filed as Exhibit 10.7 to the registrant's Registration Statement on Form S-1 (Registration No. 333-53512) and incorporated herein by reference)
10.4†	Summary Plan Description/Pension Plan dated December 30, 1994 (filed as Exhibit 10.35 to the registrant's Annual Report on Form 10-K for the year ended December 31, 1994 and incorporated herein by reference)
10.5†	Non-qualified Unfunded Supplemental Retirement Plan, as amended (filed as Exhibit 10.10 to the registrant's Registration Statement on Form S-1 (Registration No. 333-53512) and incorporated herein by reference)
10.6†	Employee Stock Purchase Plan (filed as Exhibit 10.50 for the registrant's Annual Report on Form 10-K for the year ended December 31, 1997 and incorporated herein by reference)
10.7†	

	First Amendment to Employee Stock Purchase Plan dated February 27, 2001 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 and incorporated herein by reference)
10.8†	Second Amendment to the Employee Stock Purchase Plan dated February 18, 2005 (filed as Exhibit 10.48 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2004 and incorporated herein by reference)
10.9†	Form of Change of Control Severance Agreements (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)

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Exhibit Number	Description
10.10†	Amendment to Form of Change of Control 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)
10.11	Amendment to an Extension of Office Lease dated as of December 14, 2001 (filed as Exhibit 10.45 to the registrant's Annual Report on Form 10-K for the year ended December 31, 2002 and incorporated herein by reference)
10.12†	Non-Employee Director Stock Compensation Plan as adopted on March 27, 2003 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 and incorporated herein by reference)
10.13†	Restricted Stock Plan as adopted on April 18, 2004 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 and incorporated herein by reference)
10.14†	Amendment to Restricted Stock Plan, dated December 15, 2005 (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)
10.15†	Form of Restricted Stock Unit Award Agreement under the Restricted Stock Plan (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on March 15, 2005 and incorporated herein by reference)
10.16	Amended and Restated Credit Agreement dated as of April 7, 2005 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 Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.17†	2006 Equity Incentive Compensation Plan (filed on May 17, 2006 as Exhibit 99.1 to the registrant's Registration Statement on Form S-8 (Registration No. 333-134221) and incorporated herein by reference)
10.18†	Form of Non-Employee Director Restricted Stock Award Agreement (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on May 18, 2006 and incorporated herein by reference)
10.19	Guaranty Agreement by St. Mary Energy Company in favor of Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.20	Guaranty Agreement by Nance Petroleum Corporation in favor or Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.3 to the registrant's quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.21	Guaranty Agreement by NPC Inc. in favor of Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.22	Pledge and Security Agreement between St. Mary Land & Exploration Company and Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference.)

10.23	Pledge and Security Agreement between Nance Petroleum Corporation and Wachovia Bank, National Association, as Administrative Agent, dated April 7, 2005 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference.)

Exhibit Number	Description
10.24	First Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit, Assignment, Security Agreement, Fixture Filing and Financing Statement for the Benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 7, 2005 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.25	Deed of Trust – St. Mary Land & Exploration Company to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 7, 2005 (filed as Exhibit 10.8 to the registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 and incorporated herein by reference)
10.26†	Net Profits Interest Bonus Plan, as Amended on December 15, 2005 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)
10.27†	Summary of Charitable Contributions in Honor of Thomas E. Congdon (filed as Exhibit 10.4 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)
10.28†	Summary of 2006 Base Salaries for Named Executive Officers (filed as Exhibit 10.5 to the registrant's Current Report on Form 8-K filed on December 19, 2005 and incorporated herein by reference)
10.29†	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)
10.30*†	Summary of Compensation Arrangements for Non-Employee Directors
10.31	Purchase Agreement, dated March 29, 2007, among St. Mary Land & Exploration Company, Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wachovia Capital Markets, LLC, Bear Stearns & Co. Inc., BNP Paribas Securities Corp., and UBS Securities LLC (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 4, 2007, and incorporated herein by reference)
10.32	First Amendment to Amended and Restated Credit Agreement, dated March 19, 2007, among St. Mary Land & Exploration Company, the lenders party thereto, Wachovia Bank, National Association, as issuing bank and administrative agent, Wells Fargo Bank, N.A., as syndication agent, and BNP Paribas, Comerica Bank-Texas and JPMorgan Chase Bank, N.A., as co-documentation agents (filed as Exhibit 10.2 to the registrant's Current Report on Form 8-K filed on April 4, 2007, and incorporated herein by reference)
10.33†	Net Profits Interest Bonus Plan, As Amended and Restated by the Board of Directors on July 19, 2007 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on July 25, 2007, and incorporated herein by reference)
10.34†	Cash Bonus Plan as Amended on March 28, 2008 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on April 3, 2008 and incorporated herein by reference)
10.35	Second Amended and Restated Credit Agreement dated April 10, 2008, among St. Mary Land & Exploration Company, the lenders party thereto, Wachovia Bank, National Association, as Administrative Agent, Wells Fargo Bank, N.A., as syndication agent, and BNP Paribas, Comerica Bank and JPMorgan Chase Bank,

	N.A., as co-documentation agents (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q filed on May 5, 2008 and incorporated herein by reference)
10.36†	2006 Equity Incentive Compensation Plan as Amended and Restated as of March 28, 2008 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on May 27, 2008 and incorporated herein by reference)
10.37†	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)
10.38†	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)

Exhibit Number	Description
10.39	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)
10.40	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)
10.41	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)
10.42†	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)
10.43†	St. Mary Land & Exploration Company 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)
10.44†	St. Mary Land & Exploration Company 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)
10.45†	Third Amendment to St. Mary Land & Exploration Company 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)
10.46*†	Fourth Amendment to St. Mary Land & Exploration Company Employee Stock Purchase Plan dated December 29, 2009
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

* Filed with this Form 10-K

** Furnished with this Form 10-K

† Exhibit constitutes a management contract or compensatory plan or agreement.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
St. Mary Land & Exploration Company and Subsidiaries
Denver, Colorado

We have audited the accompanying consolidated balance sheets of St. Mary Land & Exploration Company and subsidiaries (the "Company") as of December 31, 2009 and 2008, 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, 2009. 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 St. Mary Land & Exploration Company and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

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.

As discussed in Note 5 to the consolidated financial statements, the Company changed its method of accounting for convertible debt in 2009.

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, 2009, 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 23, 2010, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2010

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except share amounts)

	December 31,	
	2009	2008
ASSETS		(As adjusted, Note 5)
Current assets:		
Cash and cash equivalents	$ 10,649	$ 6,131
Short-term investments	-	1,002
Accounts receivable, net of allowance for doubtful accounts of $- in 2009 and $16,788 in 2008	116,136	157,690
Refundable income taxes	32,773	13,161
Prepaid expenses and other	14,259	22,161
Derivative asset	30,295	111,649
Deferred income taxes	4,934	-
Total current assets	209,046	311,794
Property and equipment (successful efforts method), at cost:		
Land	1,371	1,350
Proved oil and gas properties	2,797,341	2,969,722
Less - accumulated depletion, depreciation, and amortization	(1,053,518)	(947,207)
Unproved oil and gas properties, net of impairment allowance of $66,570 in 2009 and $42,945 in 2008	132,370	168,817
Wells in progress	65,771	90,910
Materials inventory, at lower of cost or market	24,467	40,455
Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization	145,392	1,827
Other property and equipment, net of accumulated depreciation of $14,550 in 2009 and $13,848 in 2008	14,404	13,458
	2,127,598	2,339,332
Other noncurrent assets:		
Derivative asset	8,251	21,541
Restricted cash subject to Section 1031 Exchange	-	14,398
Other noncurrent assets	16,041	10,182

Total other noncurrent assets		24,292		46,121
Total Assets	$	2,360,936	$	2,697,247
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$	236,242	$	254,811
Derivative liability		53,929		501
Deposit associated with oil and gas properties held for sale		6,500		-
Deferred income taxes		-		41,289
Total current liabilities		296,671		296,601
Noncurrent liabilities:				
Long-term credit facility		188,000		300,000
Senior convertible notes, net of unamortized discount of $20,598 in 2009, and $28,787 in 2008		266,902		258,713
Asset retirement obligation		60,289		108,755
Asset retirement obligation associated with oil and gas properties held for sale		18,126		238
Net Profits Plan liability		170,291		177,366
Deferred income taxes		308,189		354,328
Derivative liability		65,499		27,419
Other noncurrent liabilities		13,399		11,318
Total noncurrent liabilities		1,090,695		1,238,137
Commitments and contingencies				
Stockholders' equity:				
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 62,899,122 shares in 2009 and 62,465,572 shares in 2008; outstanding, net of treasury shares: 62,772,229 shares in 2009 and 62,288,585 shares in 2008		629		625
Additional paid-in capital		160,516		141,283
Treasury stock, at cost: 126,893 shares in 2009 and 176,987 shares in 2008		(1,204)		(1,892)
Retained earnings		851,583		957,200
Accumulated other comprehensive income (loss)		(37,954)		65,293
Total stockholders' equity		973,570		1,162,509
Total Liabilities and Stockholders' Equity	$	2,360,936	$	2,697,247

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the Years Ended December 31,		
	2009	2008	2007
		(As adjusted, Note 5)	
Operating revenues and other income:			
Oil and gas production revenue	$ 615,953	$ 1,259,400	$ 912,093
Realized oil and gas hedge gain (loss)	140,648	(101,096)	24,484
Marketed gas system revenue	58,459	77,350	45,149
Gain (loss) on divestiture activity (Note 3)	11,444	63,557	(367)
Other revenue	5,697	2,090	8,735
Total operating revenues and other income	832,201	1,301,301	990,094
Operating expenses:			
Oil and gas production expense	206,800	271,355	218,208
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	304,201	314,330	227,596
Exploration	62,235	60,121	58,686
Impairment of proved properties	174,813	302,230	-
Abandonment and impairment of unproved properties	45,447	39,049	4,756
Impairment of materials inventory	14,223	-	-
Impairment of goodwill	-	9,452	-
General and administrative	76,036	79,503	60,149
Bad debt expense (recovery)	(5,189)	16,735	-
Change in Net Profits Plan liability	(7,075)	(34,040)	50,823
Marketed gas system expense	57,587	72,159	42,485
Unrealized derivative (gain) loss	20,469	(11,209)	5,458
Other expense	13,489	10,415	2,522
Total operating expenses	963,036	1,130,100	670,683
Income (loss) from operations	(130,835)	171,201	319,411
Nonoperating income (expense):			
Interest income	227	485	746
Interest expense	(28,856)	(26,950)	(24,046)
Income (loss) before income taxes	(159,464)	144,736	296,111

Income tax benefit (expense)		60,094			(57,388	)		(109,013	)
Net income (loss)	$	(99,370	)	$	87,348		$	187,098
Basic weighted-average common shares outstanding		62,457			62,243			61,852
Diluted weighted-average common shares outstanding		62,457			63,133			64,850
Basic net income (loss) per common share	$	(1.59	)	$	1.40		$	3.02
Diluted net income (loss) per common share	$	(1.59	)	$	1.38		$	2.90

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(In thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balances, December 31, 2006	55,251,733	$ 553	$ 38,940	(250,000)	$ (4,272)	$ 695,224	$ 12,929	$ 743,374
Comprehensive income, net of tax:								
Net income (As adjusted, Note 5)	-	-	-	-	-	187,098	-	187,098
Change in derivative instrument fair value	-	-	-	-	-	-	(154,497)	(154,497)
Reclassification to earnings	-	-	-	-	-	-	(15,470)	(15,470)
Minimum pension liability adjustment	-	-	-	-	-	-	70	70
Total comprehensive income								17,201
Cash dividends, $ 0.10 per share	-	-	-	-	-	(6,284)	-	(6,284)
Treasury stock purchases	-	-	-	(792,216)	(25,957)	-	-	(25,957)
Issuance of common stock under Employee Stock Purchase Plan	29,534	-	919	-	-	-	-	919
Conversion of 5.75% Senior Convertible Notes due 2022 to common stock, including income tax benefit of conversion	7,692,295	77	106,854	-	-	-	-	106,931
Issuance of common stock upon settlement of RSUs following expiration of restriction period,	302,370	3	(4,569)	-	-	-	-	(4,566)

net of shares used for tax withholdings								
Sale of common stock, including income tax benefit of stock option exercises	733,650	7	19,011	-	-	-	-	19,018
3.50% Senior Convertible Notes conversion feature	-	-	41,843	-	-	-	-	41,843
Stock-based compensation expense	1,250	-	8,915	32,504	1,180	-	-	10,095
Balances, December 31, 2007 (As adjusted, Note 5)	64,010,832	$ 640	$ 211,913	(1,009,712)	$ (29,049)	$ 876,038	$ (156,968)	$ 902,574
Comprehensive income, net of tax:								
Net income (As adjusted, Note 5)	-	-	-	-	-	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,								
	482,602	5	(6,910)	-	-	-	-	(6,905)

net of shares used for tax withholdings								
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 (As adjusted, Note 5)	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

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Years Ended December 31,		
	2009	2008	2007
		(As adjusted, Note 5)	
Cash flows from operating activities:			
Net income (loss)	$ (99,370)	$ 87,348	$ 187,098
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
(Gain) loss on divestiture activities	(11,444)	(63,557)	367
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	304,201	314,330	227,596
Exploratory dry hole expense	7,810	6,823	14,365
Impairment of proved properties	174,813	302,230	-
Abandonment and impairment of unproved properties	45,447	39,049	4,756
Impairment of materials inventory	14,223	-	-
Impairment of goodwill	-	9,452	-
Stock-based compensation expense*	18,765	14,812	10,095
Bad debt expense (recovery)	(5,189)	16,735	-
Change in Net Profits Plan liability	(7,075)	(34,040)	50,823
Unrealized derivative (gain) loss	20,469	(11,209)	5,458
Loss related to hurricanes	8,301	6,980	-
(Gain) loss on insurance settlement	-	2,296	(5,243)
Amortization of debt discount and deferred financing costs	12,213	9,344	5,413
Deferred income taxes	(39,735)	38,164	91,418
Plugging and abandonment	(26,396)	(9,168)	(12,393)
Other	3,382	3,875	1,896
Changes in current assets and liabilities:			

Accounts receivable	46,743	(14,327)	(6,557)
Refundable income taxes	(19,612)	(12,228)	6,751
Prepaid expenses and other	(6,626)	(1,504)	19,375
Accounts payable and accrued expenses	(4,814)	(12,348)	40,769
Excess income tax benefit associated with stock awards	-	(13,867)	(9,933)
Net cash provided by operating activities	436,106	679,190	632,054
Cash flows from investing activities:			
Proceeds from insurance settlement	16,789	-	5,948
Proceeds from sale of oil and gas properties	39,898	178,867	495
Capital expenditures	(379,253)	(746,586)	(639,010)
Acquisition of oil and gas properties	(76)	(81,823)	(182,883)
Receipts from restricted cash	14,398	-	-
Deposits to restricted cash	-	(14,398)	-
Receipts from short-term investments	1,002	170	1,450
Deposits to short-term investments	-	-	(1,168)
Other	3,150	(9,984)	10,034
Net cash used in investing activities	(304,092)	(673,754)	(805,134)
Cash flows from financing activities:			
Proceeds from credit facility	2,072,500	2,571,500	822,000
Repayment of credit facility	(2,184,500)	(2,556,500)	(871,000)
Repayment of short-term note payable	-	-	(4,469)
Debt issuance costs related to credit facility	(11,074)	-	-
Excess income tax benefit associated with stock awards	-	13,867	9,933
Proceeds from issuance of senior convertible debt, net of deferred financing cost	-	-	280,657
Proceeds from sale of common stock	3,110	11,888	10,007
Repurchase of common stock	-	(77,202)	(25,904)
Dividends paid	(6,247)	(6,186)	(6,284)
Other	(1,285)	(182)	186
Net cash (used in) provided by financing activities	(127,496)	(42,815)	215,126

Net change in cash and cash equivalents		4,518		(37,379)		42,046
Cash and cash equivalents at beginning of period		6,131		43,510		1,464
Cash and cash equivalents at end of period	$	10,649	$	6,131	$	43,510

* Stock-based compensation expense is a component of exploration expense and general and administrative expense on
the consolidated statements of operations. For the years ended December 31, 2009, 2008, and 2007, respectively,
$6.3 million, $5.8 million, and $3.2 million of stock-based compensation expense was included in exploration expense.
For the years ended December 31, 2009, 2008, and 2007, respectively, $12.5 million, $9.0 million, and $6.9 million of
stock-based compensation expense was included in general and administrative expense.

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

ST. MARY LAND & EXPLORATION 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		
	2009	2008	2007
	(In thousands)		
Cash paid for interest	$ 17,884	$ 21,976	$ 22,816
Cash paid (refunded) for income taxes	$ (9,857)	$ 17,326	$ (1,156)

In August 2009 and 2008, the Company granted 725,092 and 465,751 Performance Share Awards to
employees as equity-based compensation pursuant to the Company's Equity Incentive Compensation
Plan. The total fair value of the issuances equaled $25.8 million and $12.3 million, respectively.
The Company did not grant any Performance Share Awards in 2007.

As of December 31, 2009, 2008, and 2007, the Company issued 241,745, 428,407, and 102,634
restricted stock units, respectively, to employees as equity-based compensation, pursuant to the
Company's Equity Incentive Compensation Plan. The total fair value of the issuances was $5.8 million, $23.4
million, and $3.3 million, respectively.

As of December 31, 2009, 2008, and 2007, $109.0 million, $116.5 million, and $116.9 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, 2009, 2008, and 2007, the Company issued 50,094, 23,113, and 32,504
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 $688,000, $1,041,000, and $983,500 for the years ended December 31, 2009, 2008, and 2007, respectively.

For the years ended December 31, 2009, 2008 and 2007, the Company converted 215,700, 678,197, and 427,059 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 156,252, 482,602, and 302,370 net shares of common stock associated with these grants for the years ended December 31, 2009, 2008, and 2007, respectively. The remaining 59,448, 195,595, and 124,689, 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.

In September 2008 the Company hired a new senior executive. Upon commencement of employment, the Company issued 15,496 shares of restricted stock awards to the senior executive, of which half vested on December 15, 2009 and the remaining half will vest on December 15, 2010, provided that on such vesting dates the executive is employed by the Company. The total fair value of the issuance was $600,005.

In March 2007 the Company called the 5.75% Senior Convertible Notes for redemption. All of the note holders elected to convert the 5.75% Senior Convertible Notes to common stock. As a result, the Company issued 7,692,295 shares of common stock on March 16, 2007, in exchange for the $100 million of 5.75% Senior Convertible Notes then outstanding. The conversion was executed in accordance with the conversion provisions of the original indenture. Additionally, the conversion resulted in a $7.0 million decrease in non-current deferred income taxes payable and a corresponding increase in additional paid-in capital that resulted from the recognition of the cumulative excess tax benefit earned by the Company associated with the contingent interest feature of the notes.

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

ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2009

Note 1 – Summary of Significant Accounting Policies

Description of Operations

St. Mary Land & Exploration Company ("St. Mary" or the "Company") is an independent energy company engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil. The Company's operations are conducted entirely in the continental United States.

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 full consolidation by 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 of St. Mary and in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 855, "Subsequent Events" ("ASC Topic 855") the Company evaluated subsequent events after the balance sheet date of December 31, 2009, through the filing of this report, February 23, 2010. For additional information regarding ASC, please refer to the section titled Recently Issued Accounting Standards within Note 1 – Summary of Significant Accounting Policies.

On January 1, 2009, the adoption of new authoritative accounting guidance under FASB ASC Topic 470, "Debt" ("ASC Topic 470") required retrospective application. As a result, prior period balances presented have been adjusted to reflect the period-specific effects of applying ASC Topic 470. Please refer to Note 5 – Long-term Debt for additional information regarding adoption.

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, and the Net Profits Interest Bonus Plan ("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.

Short-term Investments

As of December 31, 2008, the Company held $1.0 million of short-term investments, which consists of a certificate of deposit. Securities categorized as held-to-maturity are stated at amortized cost whereas available-for-sale securities are marked-to-market. As of December 31, 2009, the Company held no short-term investments.

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, 2009, the Company had no allowance for doubtful accounts recorded. As of December 31, 2008, the Company had $16.8 million recorded as allowance for doubtful accounts. For additional discussion on allowance for doubtful accounts, please refer to Note 14 – SemGroup Bankruptcy.

The Company has accounts with separate banks in Denver, Colorado; Shreveport, Louisiana; Franklin, Louisiana; Tulsa, Oklahoma; and Billings, Montana. At December 31, 2009, and 2008, the Company had $2.3 million and $4.8 million, respectively, invested in money market funds and overnight investment sweep accounts. The difference between the investment amount and the cash and cash equivalents amount on the accompanying consolidated balance sheets represents uncleared disbursements and non-interest-bearing checking accounts. 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 6 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, 2009, and 2008, the Company's capitalized proved oil and gas properties included $77.8 million and $102.3 million, respectively, of estimated salvage value.

The Company follows guidance under FASB ASC Topic 932, "Extractive Activities – Oil and Gas" ("ASC Topic 932") when accounting for suspended well costs. For additional discussion, please see the heading Suspended Well Costs in Note 15 –Oil and Gas Activities.

Impairment of Proved and Unproved Properties

Producing oil and gas property costs are evaluated for impairment and reduced to fair value, which is expected future discounted cash flows, if the sum of expected undiscounted future cash flows is less than net book value pursuant to FASB ASC Topic 360, "Property, Plant, and Equipment" ("ASC Topic 360"). 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

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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, 2009, and 2008, the Company recorded proved property impairment expense of $174.8 million and $302.2 million, respectively. The Company did not incur any proved property impairment write-downs during 2007. In the first quarter of 2009, the Company incurred impairment on proved properties of $97.3 million related to assets located in the Mid-Continent region due to a significant decrease in the market price for natural gas and wider than normal differentials. In the fourth quarter of 2009, the Company incurred impairment on proved properties of $20.4 million related to assets located in the ArkaLaTex region due to decreased natural gas prices and engineering revisions. The Company incurred an additional impairment on proved properties of $14.0 million during the year related to the write-down of certain assets located in the Gulf of Mexico in which the Company is relinquishing 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 Women Basin coalbed methane project.

For the years ended December 31, 2009, 2008, and 2007, the Company recorded expense related to the abandonment and impairment of unproved properties of $45.4 million, $39.0 million, and $4.8 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.

Materials Inventory

The Company's materials inventory is primarily comprised of tubular goods to be used in future drilling or repair operations. Materials inventory is valued at the lower of cost or market and totaled $24.5 million and $40.5 million at December 31, 2009, and 2008, respectively. The Company incurred net materials inventory write-downs for year ended December 31, 2009, of $14.2 million as a result of the decrease in value of tubular goods. There were no materials inventory write-downs for the years ended December 31, 2008, and 2007.

Assets Held for Sale

In accordance with ASC Topic 360, any properties held for sale as of the date of presentation of a 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 – Acquisitions, 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.

Goodwill

Goodwill is measured as the excess of the acquisition costs over the sum of the amounts assigned to the identifiable assets acquired less liabilities assumed. Goodwill was recorded as a result of the acquisition of Agate Petroleum, Inc. in January 2005. The Company conducted an impairment review annually or more frequently if impairment indicators arose. The Company fully impaired its goodwill at December 31, 2008.

Restricted Cash

Proceeds from certain sales of oil and gas properties are held in escrow and restricted for future acquisitions under tax-free exchange agreements. These funds are invested in money market funds consisting of corporate commercial paper, repurchase agreements, and U.S. Treasury obligations and are carried at cost, which approximates fair market value.

Intangible Assets

As of December 31, 2009, and 2008, the Company's other noncurrent assets in the accompanying consolidated balance sheets include $380,000 and $1.4 million, respectively, of intangible assets. These assets arise from acquired oil and gas sale contracts with favorable pricing terms. They do not qualify as derivatives or hedges. Intangible assets of the Company are amortized using the units-of-production method and are evaluated for impairment 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, 2009, and 2008, respectively, resulted in the recording of $1.8 million to accounts receivable as of both dates and $1.2 million and $1.1 million, respectively, to accounts payable.

Derivative Financial Instruments

The Company seeks to manage or reduce commodity price risk on acquisitions of producing properties and other 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 the majority of its oil hedges to NYMEX 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.

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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.

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. 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, New York Mercantile Exchange ("NYMEX") and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates.

Major Customers

During 2009 the Company had one customer individually account for 12 percent of the Company's total oil and gas production revenue. During 2008 and 2007 no customer individually accounted for more than ten percent of the Company's total oil and gas production revenue.

Stock Based Compensation

At December 31, 2009, 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. Stock options were last issued in December 2004 and were fully vested as of December 31, 2008. The Company records expense associated with the fair value of stock-based compensation in accordance with FASB ASC Topic 718, “Compensation – Stock Compensation” (“ASC 718”). The Company used the modified-prospective method to record compensation expense associated with stock options that were outstanding and unvested as of January 1, 2006. The Company records compensation expense associated with the issuance of RSUs and PSAs based on the estimated fair value of these grants as 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 amount of the asset or liabilities are recorded or settled, respectively. When appropriate the Company records a valuation allowance to reduce deferred tax assets.

Earnings per Share

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

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

The treasury stock method is used to measure the dilutive impact of stock options, RSUs, 3.50% Senior Convertible Notes, and PSAs. In accordance with FASB ASC Topic 260, “Earnings Per Share,” when there is a loss from continuing operations, all potentially dilutive shares will be anti-dilutive. As such, there were no dilutive shares for the year ended December 31, 2009. 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,		
	2009	2008	2007
Dilutive	-	890,189	1,441,556
Anti-dilutive	1,152,127	330,231	-

The Company’s 3.50% Senior Convertible Notes, which were issued on April 4, 2007, 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 for the amount in excess of the principal amount. 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 periods ended December 31, 2009, 2008, and 2007.

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On August 1, 2009, and 2008, the Company granted 725,092 and 465,751 PSAs, respectively, for the three-year performance periods ending June 30, 2012, and 2011. At the end of each grant's three-year performance period, a multiplier will be applied to all vested PSAs to determine the number of common shares issued. The number of common shares issued is determined based on the Company's absolute stock price performance and a comparison of the Company's stock price performance to an index of its peers. The number of potentially dilutive shares related to the PSAs is based on the number of shares, if any, which would be issuable if the end of the reporting period was the end of the contingency period. Based on the Company's cumulative total shareholder return ("TSR") and the relative measure of the Company's TSR compared with the cumulative TSR of the index of its peers, there would have been potentially dilutive shares related to PSAs as of December 31, 2009. However, no dilutive shares related to PSAs were included in the diluted earnings per share calculation for the year ended December 31, 2009, because the Company recorded a loss for the period. There were no potentially dilutive shares related to PSAs included in the diluted earnings per share calculation for the years ended December 31, 2008, and 2007. For additional discussion on PSAs, please see the heading Performance Share Awards Under the Equity Incentive Compensation Plan in Note 7 – Compensation Plans.

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

	For the Years Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Net income (loss)	$ (99,370)	$ 87,348	$ 187,098
Adjustments to net income (loss) for dilution:			
Add: interest expense not incurred if 5.75% Senior Convertible Notes converted	-	-	1,285
Less: other adjustments	-	-	(13)
Less: income tax effect of adjustment items	-	-	(469)
Net income (loss) adjusted for the effect of dilution	$ (99,370)	$ 87,348	$ 187,901
Basic weighted-average common shares outstanding	62,457	62,243	61,852
Add: dilutive effect of stock options, unvested RSUs, and PSAs	-	890	1,441
Add: dilutive effect of 5.75% Senior Convertible Notes using the if-converted method	-	-	1,557
Add: dilutive effect of 3.50% Senior Convertible Notes	-	-	-
Diluted weighted-average common shares outstanding	62,457	63,133	64,850

Basic net income (loss) per common share	$	(1.59	)	$	1.40	$	3.02
Diluted net income (loss) per common share	$	(1.59	)	$	1.38	$	2.90

Comprehensive Income

Comprehensive income consists of net income, 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 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, 2007			
Before tax income (loss)	$ (272,655)	$ 119	$ (272,536)
Tax benefit (expense)	102,688	(49)	102,639
After deferred tax income (loss)	$ (169,967)	$ 70	$ (169,897)
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)

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. The Company had $188.0 million and $300.0 million in loans outstanding under its revolving credit agreement as of December 31, 2009, and 2008, respectively. The Company's 3.50% Senior Convertible Notes due 2027 (the "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 run through accumulated other comprehensive income 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. All of the Company's operations are conducted in the continental United States. The Company reports as a single industry segment. The Company's gas marketing department 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. As of and up to December 31, 2009, the Company has not been involved in any unconsolidated SPE transactions.

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

Recently Issued Accounting Standards

New authoritative accounting guidance under FASB ASC Topic 105, "Generally Accepted Accounting Principles" ("ASC Topic 105") established the FASB Accounting Standards Codification as the source of authoritative U.S. GAAP recognized by the FASB to be applied to nongovernmental entities. ASC Topic 105 also states that rules and interpretive releases of the Securities and Exchange Commission ("SEC") under federal securities laws are also sources of authoritative GAAP for SEC registrants. ASC Topic 105 supersedes existing FASB, American Institute of Certified Public Accountants, Emerging Issues Task Force, and related literature. All other accounting literature is considered non-authoritative. ASC Topic 105 changes the way the Company cites authoritative guidance within the Company's financial statements and accounting policies. The new authoritative guidance under ASC Topic 105 became effective for periods ending on or after September 15, 2009, and did not have a material impact on the Company's consolidated financial statements.

New authoritative accounting guidance under FASB ASC Topic 805, "Business Combinations" ("ASC Topic 805") requires the acquiring entity in a business combination to recognize and measure all assets and liabilities assumed in the transaction and any non-controlling interest in the acquiree at fair value as of the acquisition date. ASC Topic 805 changes the way the Company accounts for acquisitions of proved oil and gas properties. Such acquisitions will now be treated as business combinations, which will require transaction costs to be expensed as incurred, may generate gains or losses due to fair value changes between the effective and closing dates of acquisitions, and will require possible recognition of goodwill given differences between the purchase price and fair value of acquired assets. ASC Topic 805 further amends the initial recognition and measurement, subsequent measurement and accounting, and disclosures of assets and liabilities arising from contingencies in a business combination. The new authoritative guidance under ASC Topic 805 became effective for the Company on January 1, 2009, and the impact on the Company's consolidated financial statements will largely be dependent on the size and nature of the business combinations completed. The Company has not made any significant acquisitions of oil and gas properties since adoption.

New authoritative accounting guidance under FASB ASC Topic 810, "Consolidation" ("ASC Topic 810") established accounting and reporting standards that require non-controlling interests to be reported as a component of equity along with any changes in the parent's ownership interest. The new authoritative guidance under ASC Topic 810 became effective for the Company on January 1, 2009, and did not have a material impact on the Company's consolidated financial statements.

New authoritative accounting guidance under FASB ASC Topic 825, "Financial Instruments" ("ASC Topic 825") requires the Company to include disclosures about the fair value of its financial instruments whenever it issues financial information for interim reporting periods and annual reporting periods, whether recognized or not recognized in the consolidated balance sheets. The new authoritative guidance under ASC Topic 825 became effective for the Company on April 1, 2009, and did not have a material impact on the Company's consolidated financial statements.

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New authoritative accounting guidance under ASC Topic 855 established general standards of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. ASC Topic 855 requires companies to disclose the date through which the Company evaluated subsequent events, the basis for that date, and whether that date represents the date the financial statements were issued. The new authoritative guidance under ASC Topic 855 became effective for the Company on April 1, 2009, and did not have a material impact on the Company's consolidated financial statements.

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.

The FASB aligned ASC Topic 932, with all of the aforementioned SEC requirements by issuing ASC Update 2010-03. The new authoritative guidance became effective for the Company's 2009 Annual Report on Form 10-K and has been fully adopted by the Company as of December 31, 2009.

In January 2010 the FASB issued ASC Update 2010-06, "Fair Value Measurements and Disclosures" ("ASC Update 2010-06") that requires additional disclosures surrounding transfers in and out of 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. This new authoritative guidance is effective for interim and annual reporting periods beginning after December 15, 2009. The Company will apply the new authoritative guidance in the Company's March 31, 2010, Quarterly Report on Form 10-Q. ASC Update 2010-06 also requires that purchases, sales, issuances, and settlements for Level 3 measurements be disclosed. This portion of the new authoritative guidance is effective for interim and annual reporting periods beginning after December 15, 2010. The Company will apply this new authoritative guidance in the Company's March 31, 2011, Quarterly Report on Form 10-Q. The adoption of ASC Update 2010-06 will not have a material impact on the Company's financial statements.

Please refer to Note 5 – Long-term Debt, Note 8 – Pension Benefits, Note 10 - Derivative Financial Instruments, Note 11 – Fair Value Measurements, and Note 16 – Disclosures about Oil and Gas Producing Activities for additional information on the recent adoption of new authoritative accounting guidance.

Note 2 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	As of December 31,	
	2009	2008
	(In thousands)	
Accrued oil and gas sales	$ 80,085	$ 84,583
Due from joint interest owners	29,719	56,493
Settled hedge receivable	253	8,829

State severance tax refunds		4,638		5,049
Other		1,441		2,736
Total accounts receivable	$	116,136	$	157,690

Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2009	2008
	(In thousands)	
Accrued drilling costs	$ 100,960	$ 111,397
Revenue and severance tax payable	33,370	42,520
Accrued lease operating expense	13,760	20,328
Accrued property taxes	4,747	4,889
Accrued interest	3,198	2,794
Accrued compensation	23,607	18,613
Trade payables	11,633	25,629
Plug and abandonment liability	23,665	7,281
Accrued marketed gas system expense	8,313	8,892
Settled hedge payable	1,637	-
Other	11,352	12,468
Total accounts payable and accrued expenses	$ 236,242	$ 254,811

Note 3 – Acquisitions, Divestitures, and Assets Held for Sale

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 the Rocky Mountain region. The cash received at closing, including a $2.0 million deposit, net of commission costs, was $23.3 million. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during the second quarter of 2010. The estimated gain on sale related to the divestiture is approximately $12.9 million and may be impacted by the previously mentioned post-closing adjustments. The Company determined that this sale did not qualify for discontinued operations accounting under FASB ASC Topic 205, "Presentation of Financial Statements" ("ASC Topic 205").

Greater Green River Basin Divestiture

In June 2008 the Company completed the divestiture of certain non-strategic gas properties located in the Greater Green River Basin in the Rocky Mountain region as the second step of a reverse 1031 exchange. The cash received at closing, net of commission costs, was $21.9 million. The final sales price is subject to normal post-closing adjustments and is expected to be finalized during 2010. The estimated gain on sale related to the divestiture is approximately $900,000, net of commission costs and Net Profit Plan payments, and may be impacted by the previously mentioned post-closing adjustments. The Company determined that this sale did not qualify for discontinued operations accounting under ASC Topic 205.

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 the 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 this sale did not qualify for discontinued operations accounting under ASC Topic 205.

Carthage Acquisition

In March 2008, the Company acquired oil and gas properties as the first step of a reverse 1031 exchange. These properties are located primarily in the Carthage Field in Panola County, Texas and were purchased for $49.2 million in cash. After normal purchase price adjustments, the Company allocated $29.0 million to proved oil and gas properties, $20.6 million to unproved oil and gas properties, and a net $215,000 to other liabilities. The Company also recorded a $165,000 asset retirement obligation liability associated with the acquired properties. The acquisition was funded with cash on hand and borrowings under the Company's existing credit facility. During the second quarter of 2008, the Company acquired additional interests in the majority of these properties for $8.1 million.

Assets Held for Sale

In accordance with ASC Topic 360, 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, 2009, the accompanying consolidated balance sheets includes $145.4 million in book value of assets held for sale, net of accumulated depletion, depreciation, and amortization. The corresponding asset retirement obligation liability of $18.1 million is also separately presented. The above assets held for sale and asset retirement obligation liability amounts include certain non-core properties located primarily in the Rocky Mountain region that the Company began marketing in the third quarter of 2009, as well as a new package of properties located in our South Texas and Gulf Coast region. The Company determined that these sales do not qualify for discontinued operations accounting under ASC Topic 205.

In December 2009, St Mary reached an agreement for the partial sale of its previously announced divestiture package, of certain non-strategic oil and gas properties located in the Rocky Mountain region to Legacy Reserves Operating LP. The transaction has an effective date of November 1, 2009. Subsequent to year end, on February 17, 2010, the Company completed this divestiture. Total cash received, before commission costs, was $125.2 million, of which $6.5 million was received as a deposit in December 2009 and is separately presented on the accompanying consolidated balance sheets. The cash received is subject to normal post-closing adjustments and settlements.

Subsequent to year end, St Mary reached an agreement for the sale of the North Dakota portion of its previously announced divestiture package of certain non-strategic oil and gas properties located in the Rocky Mountain region to Sequel Energy Partners L.P. for $137.0 million in cash, subject to normal closing and post-closing adjustments. The agreement has an effective date of November 1, 2009, and is anticipated to close in March 2010, subject to customary closing conditions.

In the third quarter of 2009, St. Mary reclassified a portion of the assets previously classified as held for sale to assets held and used, as these assets were no longer being actively marketed. In accordance with ASC Topic 360, the Company must measure the assets at the lower of the assets carrying amount before the assets were classified as held for sale, adjusted for any depreciation and depletion expense that would have been recognized had the assets been continuously classified as held and used, or the assets fair value at the subsequent date that the decision not to actively market the assets was determined. As a result of this measurement the Company recognized a $9.8 million loss on unsuccessful sale of properties, which is included in gain (loss) on divestiture activity in the accompanying consolidated statements of operations.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Current income tax (benefit)			
Federal	$ (21,926)	$ 17,863	$ 15,136
State	1,567	1,361	2,459
Deferred income tax expense (benefit)	(39,735)	38,164	91,418
Total income tax expense (benefit)	$ (60,094)	$ 57,388	$ 109,013
Effective tax rates	37.7%	39.7%	36.8%

As a result of the exercise of stock options, the Company reduced its income tax payable in 2008 and 2007. The excess income tax benefit to the Company associated with stock awards was $13.9 million in 2008 and $9.9 million in 2007. There was no income tax benefit associated with stock awards in 2009.

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

	December 31,	
	2009	2008
	(In thousands)	
Deferred tax liabilities:		
Oil and gas properties	$ 419,585	$ 433,536
Unrealized derivative asset	-	42,407
Interest on Senior Convertible Notes	1,937	2,450
Other	1,378	3,635
Total deferred tax liabilities	422,900	482,028
Deferred tax assets:		
Net Profits Plan liability	63,902	66,800
Unrealized derivative liability	21,107	1,072
State tax net operating loss carryforward or carryback	10,915	7,215
	9,647	7,291

Stock compensation				
Other long-term liabilities		17,277		7,179
Total deferred tax assets		122,848		89,557
Valuation allowance		(3,203)		(3,146)
Net deferred tax assets		119,645		86,411
Total net deferred tax liabilities		303,255		395,617
Less: current deferred income tax liabilities		(1,366)		(42,766)
Add: current deferred income tax assets		6,300		1,477
Non-current net deferred tax liabilities	$	308,189	$	354,328
Current federal income tax refundable	$	32,773	$	13,136
Current state income tax refundable (payable)	$	(168)	$	25

At December 31, 2009, the Company had estimated state net operating loss carryforwards of approximately $259 million expiring between 2010 and 2029. The Company has a federal AMT credit carry forward of $2.1 million which will not expire, and other state tax credits of $285,000 which expire between 2010 and 2019. 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 has adjusted its valuation allowances accordingly. A small portion of the valuation allowance relates to the Net Profits Plan liability and reflects an estimate of future executive compensation that may not be deductible for income tax purposes when future cash payments occur under the plan.

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, and other permanent differences, as follows:

	For the Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Federal statutory tax (benefit)	$ (55,812)	$ 50,526	$ 103,555
Increase (decrease) in tax resulting from			
State tax (benefit) (net of federal benefit)	(5,141)	4,669	5,111
Goodwill	-	3,308	-
Change in valuation allowance	56	(409)	896
Statutory depletion	(189)	(294)	(407)
Domestic production activities deduction	-	(275)	(384)
Other	992	(137)	242
Income tax expense (benefit) from operations	$ (60,094)	$ 57,388	$ 109,013

Acquisitions, drilling, 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 property. As its apportionment factors change, the Company's blended state income tax rate changes. This change, when applied to the Company's total temporary difference, 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 dispositions 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 2006. 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 dollars related to its 2008 income tax return. At December 31, 2009 the Company is awaiting a $5.5 million dollar refund related to filing an amended return for its 2006 tax year reflecting a net operating loss carry back from the Company's 2008 tax year. The Company's remaining receivable balance reflects its intention to carry back a net operating loss generated in 2009 to prior years.

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. For additional discussion please refer to the section titled Goodwill within Note 1 – Summary of Significant Accounting Policies. This resulted in a 2.2 percent increase in the Company's effective tax rate for the year ended December 31, 2008. The Company received $1.0 million in the first quarter of 2008 for income tax refunds and accrued interest resulting from a carry-over of minimum tax credits to its 2003 tax year.

The Company adopted the uncertainty provision of FASB ASC Topic 740, "Income Taxes" on January 1, 2007. There was no financial statement adjustment required as a result of adoption. At adoption, the Company had a long-term liability for an unrecognized tax benefit of $1.0 million and accumulated interest liability of $92,000. The entire amount of unrecognized tax benefit would affect the Company's effective tax rate if recognized. Interest expense in the 2009 accompanying consolidated statements of operation includes a nominal $12,000 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 year ended December 31, 2009, 2008, and 2007.

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

	For the Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Beginning balance	$ 994	$ 957	$ 1,112
Additions for tax positions of prior years	231	173	233
Reductions for lapse of statute of limitations	(341)	(136)	(388)
Ending balance	$ 884	$ 994	$ 957

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 specifies a maximum loan amount of $1.0 billion and has a maturity date of July 31, 2012. The authorized borrowing base under the credit facility is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties and other assets, as determined by the bank syndicate. On September 29, 2009, the lending group redetermined and maintained the Company's reserve-backed borrowing base under the credit facility at an amount of $900 million. 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, 2009, 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%	>25% <50%	>50% <75%	>75%
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 $211.0 million, $188.0 million, and $300.0 million in outstanding loans under its revolving credit agreement on February 16, 2010, December 31, 2009, and 2008, respectively. The Company had $467.0 million, $489.4 million, and $200.0 million of available borrowing capacity under this facility as of February 16, 2010, December 31, 2009, and 2008, respectively. The Company had a single letter of credit outstanding in the amount of $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. There was no letter of credit outstanding as of February 16, 2010.

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. Subsequent to year end 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.

New authoritative accounting guidance under FASB ASC Topic 470

Effective January 1, 2009, the new authoritative accounting guidance under ASC Topic 470 required issuers of convertible debt that may be settled fully or partially in cash upon conversion to account separately for the liability and equity components of the debt in a manner that reflects the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. ASC Topic 470 applies to the Company's 3.50% Senior Convertible Notes. Under the adoption provisions of ASC Topic 470, the Company retrospectively applied its provisions and restated the Company's consolidated financial statements for prior periods.

Under the provisions of ASC Topic 470, $42.0 million of the carrying value of the 3.50% Senior Convertible Notes was recorded as additional paid-in capital as of the April 4, 2007, issuance date. This amount represents the equity component of the proceeds from the 3.50% Senior Convertible Notes, calculated assuming a 7.0% discount rate, which is the estimate of what the Company's borrowing rate for a similar debt instrument without the conversion feature would have been at the date of the issuance of the 3.50% Senior Convertible Notes. Upon retrospective application, the adoption resulted in a $6.8 million decrease in the Company's retained earnings at December 31, 2008, which was comprised of non-cash interest expense of $10.8 million, net of capitalized interest of $2.2 million, less deferred taxes of $4.0 million, for the period from April 4, 2007, through December 31, 2008. The following table presents the December 31, 2008, consolidated balance sheet line items as adjusted and as originally reported:

	As of December 31, 2008	
	As Adjusted	As Originally Reported
	(In thousands)	
Proved oil and gas properties	$ 2,969,722	$ 2,967,491
Senior Convertible Notes	258,713	287,500
Noncurrent deferred income taxes	354,328	358,334
Additional paid-in capital	141,283	99,440
Retained earnings	957,200	964,019

As of December 31, 2009, and 2008, the carrying value of the equity component was $42.0 million. The principal amount of the 3.50% Senior Convertible Notes, the unamortized debt discount, and the net carrying amounts were as follows:

	As of December 31, 2009	As of December 31, 2008 (As Adjusted)
	(In thousands)	
Senior Convertible Notes	$ 287,500	$ 287,500
Unamortized debt discount	(20,598)	(28,787)
Net carrying amount of the 3.50% Senior Convertible Notes	$ 266,902	$ 258,713

The Company amortized $8.2 million, $7.6 million, and $5.4 million of the debt discount for the years ended December 31, 2009, 2008, and 2007, respectively. Accumulated amortization related to the debt discount was $21.2 million and $13.0 million for the years ended December 31, 2009, and 2008, respectively. The remaining unamortized debt discount will be amortized through March 2012 using the interest method.

The consolidated statements of operations were retrospectively adjusted compared to previously reported amounts as follows:

	For the Year Ended December 31, 2008		For the Year Ended December 31, 2007	
	As Adjusted	As Originally Reported	As Adjusted	As Originally Reported
	(In thousands, except per share amounts)			
Interest expense	$ 26,950	$ 20,275	$ 24,046	$ 19,895
Income tax expense	57,388	59,858	109,013	110,550
Net income	87,348	91,553	187,098	189,712
Basic net income per common share	$ 1.40	$ 1.47	$ 3.02	$ 3.07
Diluted net income per common share	$ 1.38	$ 1.45	$ 2.90	$ 2.94

Weighted-Average Interest Rate Paid and Capitalized Interest

The weighted-average interest rate paid in 2009, 2008, and 2007, was 5.4 percent, 5.8 percent, and 6.7 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of debt discount, amortization of the contingent interest embedded derivative associated with the 5.75% Senior Convertible Notes for 2007, and the effect of interest rate swaps. The average outstanding loan balance in 2009 increased in comparison to the average outstanding loan balance in 2008, while the rates associated with the balances decreased. The decrease is attributed to significantly lower LIBOR and Prime rates in 2009 compared to 2008. Capitalized interest costs for the Company for the years ended December 31, 2009, 2008, and 2007, were $1.9 million, $4.7 million, and $6.7 million, respectively.

Note 6 – Commitments and Contingencies

The Company has entered into various operating leases, which include drilling rig contracts, of approximately $20.5 million, office space leases including maintenance of approximately $34.5 million, compressor contracts of approximately $2.7 million, and vehicle leases of approximately $2.3 million. The annual minimum lease payments for the next five years and thereafter are presented below:

Years Ending December 31,		(In thousands)
2010	$	27,779
2011		6,438
2012		3,249
2013		2,973
2014		2,367
Thereafter		18,275
Total	$	61,081

The Company leases office space under various operating leases with terms extending as far as May 31, 2022. Rent expense, net of sublease income, was $2.3 million, $2.4 million, and $1.9 million in 2009, 2008, and 2007, respectively. The Company also leases office equipment under various operating leases. As of December 31, 2009, the Company has a sublease through May 2012 with payments due to St. Mary of $185,000 per year through 2011 and $62,000 in 2012. This sublease was terminated on January 15, 2010.

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.

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 $7.8 million, $6.4 million, and $3.6 million of cash bonus expense related to the specific performance year for the years ended December 31, 2009, 2008, and 2007, 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. These disclosures reflect the disclosure requirements for all equity awards still outstanding.

In May 2006 the stockholders approved the 2006 Equity Incentive Compensation Plan, which was subsequently renamed the Equity Incentive Compensation Plan (the "Equity Plan"), to authorize the issuance of restricted stock, RSUs, non-qualified stock options, incentive stock options, stock appreciation rights, and stock-based awards to key employees, consultants, and members of the Board of Directors of St. Mary or any affiliate of St. Mary. 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.

As of December 31, 2009, 1.8 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 counts 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

In 2007, PSAs became the primary form of long-term equity incentive compensation replacing standalone RSU grants and awards of interest in pools under the Net Profits Plan. PSAs represent the right to receive a share of the Company's common stock which can be multiplied by a factor ranging from zero to two times the number of PSAs granted on the award date depending 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 cumulative TSR for the performance period and the relative measure of the Company's TSR compared with the cumulative TSR of an index comprised of certain peer companies for the performance period.

On August 1, 2009, the Company granted 725,092 PSAs with a performance period ending June 30, 2012. The PSAs will vest 1/7th on August 1, 2010, 2/7ths on August 1, 2011, and 4/7ths on August 1, 2012. The fair value of the Company's PSAs granted on August 1, 2009, was $25.8 million and is being recognized as general and administrative and exploration expense over the vesting period of the award.

On August 1, 2008, the Company granted 465,751 PSAs with a performance period ending June 30, 2011. The PSAs will vest 1/7th on August 1, 2009, 2/7ths on August 1, 2010, and 4/7ths on August 1, 2011. The fair value of the Company's PSAs granted on August 1, 2008, was $12.3 million and is being recognized as general and administrative and exploration expense over the vesting period of the award.

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, 2009, and 2008, is presented in the following table:

	2009		2008	
	PSAs	Weighted-Average Grant-Date Fair Value	PSAs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	464,333	$ 26.48	-	$ -
Granted	725,092	$ 35.59	465,751	$ 26.48
Vested(1)	(76,781)	$ 27.20	-	$ -
Forfeited	(43,554)	$ 28.62	(1,418)	$ 26.48
Non-vested at end of year	1,069,090	$ 32.52	464,333	$ 26.48

(1) The number of shares vested represents 1/7th of the August 1, 2008, PSA grant assuming a one multiplier. The final number of shares vested 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 year ended December 31, 2009, was $1.8 million. General and administrative and exploration expense recorded for PSAs was $9.3 million and $2.5 million for the years ended December 31, 2009, and 2008, respectively. As of December 31, 2009, there was $25.0 million of total unrecognized expense related to PSAs, which is being amortized through 2012.

Restricted Stock Incentive Program Under the Equity Incentive Compensation Plan

The Company historically had a long-term incentive program whereby grants of restricted stock or RSUs were awarded to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards were determined at the discretion of the Board of Directors and were 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 were determined annually based on the same Company performance formula used to determine the annual cash bonus. RSUs were also issued in 2008 as the Company transitioned to using PSAs as the primary long-term equity incentive compensation awards and again in 2009 as a component of the Company’s long-term equity incentive compensation program.

The Company issued 241,745 RSUs on August 1, 2009, with a weighted-average grant-date fair value of $23.87 with a total fair value of $5.8 million. These RSUs vest 1/7th on August 1, 2010, 2/7ths on August 1, 2011, and 4/7ths on August 1, 2012 and is being recognized as general and administrative and exploration expense over the vesting period of the award.

St. Mary issued 265,373 RSUs on June 30, 2008, as a transitional award to employees when the Company moved from the legacy equity incentive compensation plan to the new 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. General and administrative and exploration expense is recorded over the vesting period of the award.

The Company issued 158,744 RSUs on February 28, 2008, related to 2007 performance, and 78,657 RSUs on February 28, 2007, related to 2006 performance. The total fair value associated with these issuances was $6.0 million for the 2008 grant and $2.5 million for the 2007 issuance as measured on the respective grant dates. These granted RSUs vested 25 percent immediately upon grant and 25 percent on each of the first three anniversary dates of the grant. The fair values of these awards are being recognized as general and administrative and exploration expense over the vesting period of the awards.

The Company issued an additional 4,290 and 23,977 RSUs to certain employees during 2008 and 2007, respectively. The total fair value associated with the 2008 and 2007 issuances was $164,000 and $803,000, respectively, as measured on the respective grant dates. These grants have various vesting schedules.

For RSUs awarded prior to 2006, vested shares of common stock underlying the RSU grants were issued on the third anniversary of the grant, at which time the shares carried no further restrictions. On December 31, 2007 the Company eliminated the restriction period that extends beyond the vesting period so shares are now issued without restriction upon vesting, rather than on the third anniversary of the award for all awards granted after 2005. Therefore the fair value of a RSU award granted after December 31, 2007, is equal to the market value of the underlying stock on the date of the grant. This change fell within the safe harbor adoption provisions of the U.S. Treasury regulations interpreting IRC provisions governing deferred compensation. A mutual election of the employee and the Company was required to effect this change for each outstanding award. The majority of the awards were modified by mutual election, and as such, the incremental value associated with removal of this restriction period was $556,000 and is being amortized over the remaining respective service periods for these awards.

For grants made beginning with the 2006 grant period, the Company is using the accelerated amortization method whereby approximately 48 percent of the total estimated compensation expense is recognized in the first year of the vesting period. As of December 31, 2009, a total of 408,356 RSUs were outstanding, of which 1,233 were vested. The total general and administrative and exploration expense associated with RSUs for the years ended December 31, 2009, 2008, and 2007, was $7.9 million, $11.0 million, and $8.4 million, respectively. As of December 31, 2009, there was $10.0 million of total unrecognized expense related to unvested RSU awards and is being amortized through 2012.

During 2009, 2008, and 2007, the Company converted 215,700, 678,197, and 427,059 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 156,252; 482,602; and 302,370 for 2009, 2008, and 2007, respectively. The remaining 59,448, 195,595, and 124,689 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs for 2009, 2008, and 2007, respectively.

In accordance with ASC Topic 718, when measuring compensation expense related to the grant of RSUs the Company estimates the fair value of the award on the grant date. For grants prior to January 1, 2008, the Company had a restriction period beyond vesting. Therefore, the fair value of the RSUs was inherently less than the market value of an unrestricted share of St. Mary’s common stock. The fair value of RSUs with restriction periods beyond the vesting dates were measured using the Black-Sholes option-pricing model. The Company’s computation of expected volatility was based on the historic volatility of St. Mary’s common stock. The Company’s computation of expected life was determined based on historical experience of similar awards, giving consideration to the contractual terms of the awards, vesting schedules, and expectations of future employee behavior. The interest rate for periods within the contractual life of the award was based on the U.S. Treasury constant maturity yield at the time of the grant.

The fair values of RSU awards granted prior to January 1, 2008, were estimated using the following weighted-average assumptions:

	For the Year Ended December 31, 2007
Risk free interest rate	4.5%
Dividend yield	0.3%

Volatility factor of the expected market price of the Company's common stock	32.0%
Expected life of the awards (in years)	3

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Stock Awards Under the Equity Incentive Compensation Plan

As part of hiring a new senior executive in the second quarter of 2006, St. Mary 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 will 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 2009, 2008, and 2007 the Company issued 1,250, 3,750, and 1,250 worth of guaranteed and contingent shares with associated fair values of $45,000, $142,000, and $45,000, respectively. 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, St. Mary granted a special restricted stock award of 15,496 shares that vested one half on December 15, 2009, and the other half will vest on December 15, 2010. The fair value of this award was $600,005 and is being recorded as compensation expense over the vesting period. For the years ended December 31, 2009, and 2008, the Company recorded general and administrative and exploration expense of $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, 2009, 2008, and 2007, is presented below:

	2009		2008		2007	
	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	402,297	$ 48.24	289,385	$ 32.26	506,161	$ 28.92
Granted	241,745	$ 23.87	443,903	$ 53.81	102,634	$ 32.45
Vested	(211,092)	$ 46.26	(291,659)	22.92	(268,123)	25.94
Forfeited	(25,827)	$ 50.35	(39,332)	$ 37.82	(51,287)	$ 31.77
Non-vested at end of year	407,123	$ 34.67	402,297	$ 48.24	289,385	$ 32.26

The total fair value of RSUs that vested during the years ended December 31, 2009, 2008, and 2007, was $4.9 million, $9.4 million, and $9.8 million, respectively.

ASC Topic 718 requires cash flows resulting from excess tax benefits 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 has recorded $13.9 million and $9.9 million of excess tax benefits for the years ended December 31, 2008, and 2007, 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, 2009, 2008, and 2007, was $1.6 million, $10.8 million, and $9.1 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 to date 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 years ended December 31, 2008, and 2007, the Company recognized general and administrative and exploration expense of $17,000 and $437,000, respectively, related to stock options that were outstanding and unvested upon adoption of ASC Topic 718 on January 1, 2006. There was no expense associated with stock options or unvested stock options outstanding for the year ended December 31, 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, 2007			
Outstanding, start of year	3,121,602	$ 12.56	
Granted	-	-	
Exercised	(733,650)	$ 12.38	
Forfeited	(2,452)	$ 7.34	
Outstanding, end of year	2,385,500	$ 12.62	$ 62,007,749
Vested, or expected to vest, end of year	2,385,500	$ 12.62	$ 62,007,749
Exercisable, end of year	2,378,000	$ 12.62	$ 61,814,737
For the year ended December 31, 2008			
Outstanding, start of year	2,385,500	$ 12.62	
Granted	-	-	
Exercised	(868,372)	$ 12.47	

Forfeited	(7,418	)$	13.39			
Outstanding, end of year	1,509,710	$	12.69	$	11,529,600	
Vested, or expected to vest, 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			
Granted	-		-			
Exercised	(189,740	)$	8.40			
Forfeited	(45,050	)$	13.38			
Outstanding, end of year	1,274,920	$	13.31	$	26,684,106	
Vested, or expected to vest, end of year	1,274,920	$	13.31	$	26,684,106	
Exercisable, end of year	1,274,920	$	13.31	$	26,684,106	

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A summary of additional information related to options outstanding as of December 31, 2009, follows:

	Options Outstanding and Exercisable		
Range of Exercise Prices	Number Of Options Outstanding and Exercisable	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price
$ 7.97 - $ 10.86	192,230	2.0 years	$ 10.05
11.95 - 12.03	176,035	2.6 years	11.99
12.08 - 12.08	13,080	2.4 years	12.08
12.50 - 12.50	143,378	3.0 years	12.50
12.53 - 12.66	204,202	3.5 years	12.58
13.39 - 13.39	30,593	3.8 years	13.39
13.65 - 13.65	126,839	3.5 years	13.65
14.25 - 14.25	188,531	4.0 years	14.25
16.66 - 16.66	141,400	1.0 years	16.66
20.87 - 20.87	58,632	5.0 years	20.87
Total	1,274,920		

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

Director Shares

In 2009, 2008, and 2007, the Company issued 50,094, 23,113, and 32,504 shares, respectively, of restricted common stock from treasury to its non-employee directors pursuant to the Company's Equity Plan. The Company recorded general and administrative and exploration expense related to the issuances of shares to non-employee directors of $688,000, $1.0 million, and $984,000 for the years ended December 31, 2009, 2008, and 2007, respectively.

Employee Stock Purchase Plan

Under the St. Mary Land & Exploration Company 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 will be 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 1,468,275 shares are available for issuance as of December 31, 2009. Shares issued under the ESPP totaled 86,308 in 2009, 45,228 in 2008, and 29,534 in 2007. Total proceeds to the Company for the issuance of these shares was $1.5 million in 2009, $1.1 million in 2008, and $919,000 in 2007.

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

	For the Years Ended December 31,		
	2009	2008	2007
Risk free interest rate	0.3%	1.2%	4.1%
Dividend yield	0.5%	0.2%	0.3%
Volatility factor of the expected market price of the Company's common stock	95.14%	81.5%	27.2%
Expected life (in years)	0.5	0.5	0.5

The Company expensed $848,000, $307,000, and $260,000 for the years ended December 31, 2009, 2008, and 2007, respectively, based on the estimated fair value of grants on the respective grant dates.

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. 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, $2.0 million, and $1.5 million for the years ended December 31, 2009, 2008, and 2007, 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, 2009.

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,		
	2009	2008	2007
		(In thousands)	

General and administrative expense	$	18,399	$	29,713	$	25,030
Exploration expense		1,463		6,604		6,881
Total	$	19,862	$	36,317	$	31,911

Additionally, the Company made cash payments under the Net Profits Plan of $724,000 for the year ended December 31, 2009, as a result of sales proceeds from properties sold during the fourth quarter of 2009. For the year ended December 31, 2008, the Company made cash payments under the Net Profits Plan of $15.1 million as a result of sales proceeds from the Abraxas and Greater Green River Basin divestitures. The cash payments are accounted for as a reduction in the gain (loss) on divestiture activity in the accompanying consolidated statements of operations. There were no significant cash payments made under the Net Profits Plan as the result of property divestitures during 2007.

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,		
	2009	2008	2007
	(In thousands)		
General and administrative expense (benefit)	$ (6,572)	$ (29,672)	$ 39,866
Exploration expense (benefit)	(503)	(4,368)	10,957
Total	$ (7,075)	$ (34,040)	$ 50,823

Note 8 – Pension Benefits

New authoritative accounting guidance under FASB ASC Topic 715

Effective January 1, 2009, new authoritative accounting guidance under FASB ASC Topic 715, “Compensation – Retirement Benefits” (“ASC Topic 715”) amends the disclosure requirements of plan assets for defined benefit pensions and other postretirement plans. The objective of ASC Topic 715 is to provide users of financial statements with an understanding of how investment allocation decisions are made, the major categories of plan assets held by the plans, the inputs and valuation techniques used to measure the fair value of plan assets, significant concentration of risk within a company’s plan assets, fair value measurements determined using significant unobservable inputs, and a reconciliation of changes between the beginning and ending balances for all level 3 inputs.

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 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

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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,	
	2009	2008
	(In thousands)	
Change in benefit obligations		
Projected benefit obligation at beginning of year	$ 14,786	$ 14,744
Service cost	2,500	2,229
Interest cost	934	889
Actuarial (gain) loss	1,275	(166)
Benefits paid	(945)	(2,910)
Projected benefit obligation at end of year	$ 18,550	$ 14,786
Change in plan assets		
Fair value of plan assets at beginning of year	$ 6,552	$ 8,755
Actual return on plan assets	1,466	(1,782)
Employer contribution	2,028	2,489
Benefits paid	(945)	(2,910)
Fair value of plan assets at end of year	$ 9,101	$ 6,552
Funded status at end of year	$ 9,449	$ 8,234

The Company's underfunded status for the Pension Plans for the years ended December 31, 2009, and 2008, is $9.4 million and $8.2 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 are expected to be returned to the Company during the fiscal year ended December 31, 2009. 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,	
	2009	2008
	(In thousands)	
Projected benefit obligation	$ 18,550	$ 14,786
Accumulated benefit obligation	$ 13,278	$ 9,922
Less: Fair value of plan assets	9,101	6,552
Underfunded accumulated benefit obligation	$ 4,177	$ 3,370

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, 2009, and 2008, consist of:

	As of December 31,	
	2009	2008
	(In thousands)	
Unrecognized actuarial losses	$ 4,322	$ 4,441
Unrecognized prior service costs	-	-
Unrecognized transition obligation	-	-
Accumulated other comprehensive income	$ 4,322	$ 4,441

The estimated net loss that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is $267,000.

Other pre-tax changes recognized in other comprehensive income during 2009, 2008, and 2007, were as follows:

	As of December 31,		
	2009	2008	2007
	(In thousands)		
Net actuarial gain (loss)	$ (239)	$ (2,181)	$ (99)
Less: Amortization of:			
Prior service cost	-	-	-
Actuarial gain (loss)	(358)	(240)	(218)
Total other comprehensive income	$ 119	$ (1,941)	$ 119

Components of Net Periodic Benefit Cost for Both Pension Plans

	For the Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Components of net periodic benefit cost			
Service cost	$ 2,500	$ 2,229	$ 1,911
Interest cost	934	889	793

Expected return on plan assets that reduces periodic pension cost	(430)	(565)	(540)
Amortization of prior service cost	-	-	-
Amortization of net actuarial loss	372	248	218
Net periodic benefit cost	$ 3,376	$ 2,801	$ 2,382

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. 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,		
	2009	2008	2007
Projected benefit obligation			
Discount rate	6.1%	6.6%	6.1%
Rate of compensation increase	6.2%	6.2%	6.2%
Net periodic benefit cost			
Discount rate	6.6%	6.1%	5.9%
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:

	Target	As of December 31,	
Asset Category	2010	2009	2008
Equity securities	60%	61.3%	52.0%
Debt securities	40%	38.7%	48.0%
Other	-%	-%	-%
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 2009 and 2008. 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, 2009, utilizing the fair value hierarchy discussed in Note 11- Fair Value Measurements is as follows:

Assets:	Level 1	Level 2	Level 3
		(In thousands)	
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	$ -	$ -

(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.

Contributions

The Company contributed $2.0 million, $2.5 million, and $2.2 million, to the Pension Plans in the years ended December 31, 2009, 2008, and 2007, respectively. Under the Pension Protection Act of 2006, St. Mary is not required to make a minimum contribution to the Pension Plans in 2010.

Benefit Payments

The Pension Plans made actual benefit payments of $945,000, $2.9 million, and $1.8 million in the years ended December 31, 2009, 2008, and 2007, respectively. Expected benefit payments over the next ten years are as follows (in thousands):

Years Ended December 31,	
2010	$ 610
2011	1,286
2012	1,305
2013	2,381
2014	2,840
2015 through 2019	$ 15,872

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,	
	2009	2008
	(In thousands)	
Beginning asset retirement obligation	$ 116,274	$ 108,284
Liabilities incurred	2,784	11,684
Liabilities settled	(28,958)	(24,154)
Accretion expense	8,673	7,486
Revision to estimated cash flows	3,307	12,974
Ending asset retirement obligation	$ 102,080	$ 116,274

Accounts payable and accrued expenses as of December 31, 2009, contain $23.7 million related to the Company’s asset retirement obligation. The amount relates to 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. Accounts payable and accrued expenses contained $7.3 million related to the Company’s asset retirement obligation as of December 31, 2008. The amount relates to the estimated plugging and abandonment costs associated with one offshore platform that was destroyed during Hurricane Ike. Please refer to Note 13 – Hurricanes for additional details.

Note 10 – Derivative Financial Instruments

New Authoritative Accounting Guidance under FASB ASC Topic 815

Effective January 1, 2009, new authoritative accounting guidance under FASB ASC Topic 815, “Derivatives and Hedging” (“ASC Topic 815”) requires entities to provide greater transparency about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for, and how derivative instruments and related hedged items affect an entity’s financial position, results of operations, and cash flows.

Oil, Natural Gas and NGL Commodity Hedges

To mitigate a portion of the potential exposure to adverse market changes in oil and gas 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 natural gas liquids (“NGLs”). As of December 31, 2009, the Company has hedge contracts in place through the end of 2012 for a total of approximately 6 million Bbls of anticipated crude oil production, 63 million MMBtu of anticipated natural gas production, and 1 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil, gas and NGL derivative instruments as cash flow hedges for accounting purposes under ASC Topic 815. 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, gas or NGL at its physical location. 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, 2009, 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.

The Company's oil, gas and NGL hedges are measured at fair value and are included in the accompanying consolidated 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 derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The oil, 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 under ASC Topic 815 was a net liability of $80.9 million and a net asset of $105.3 million at December 31, 2009, and 2008, 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, 2009		Fair Value at December 31, 2008	
Derivative assets designated as cash flow hedges:			(In thousands)		
Oil, natural gas, and NGL commodity	Current assets	$	30,295	$	111,649
Oil, natural gas, and NGL commodity	Other noncurrent assets		8,251		21,541
Total derivative assets designated as cash flow hedges under ASC Topic 815		$	38,546	$	133,190
Derivative liabilities					

designated as cash flow hedges:					
Oil, natural gas, and NGL commodity	Current liabilities	$	(53,929)	$	(501)
Oil, natural gas, and NGL commodity	Noncurrent liabilities		(65,499)		(27,419)
Total derivative liabilities designated as cash flow hedges under ASC Topic 815		$	(119,428)	$	(27,920)

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 $140.6 million, a net loss of $101.1 million, and a net gain of $24.5 million from its oil, gas, NGL and interest rate derivative contracts for the years ended December 31, 2009, 2008, and 2007, respectively.

After-tax changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in accumulated other comprehensive income in the accompanying consolidated balance sheets until the hedged item is realized in earnings upon the sale of the associated hedged production. As of December 31, 2009, 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 $6.5 million.

The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to the New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI") index and natural gas derivative contracts indexed to regional index prices associated with pipelines in proximity to the Company's areas of production. 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 consolidated balance sheets (net of tax):

	Derivatives Qualifying as Cash Flow Hedges	For the Years Ended December 31,		
		2009	2008	2007
		(In thousands)		
Amount of (Gain) Loss on Derivatives Recognized in OCI During the Period (Effective Portion)	Commodity hedges	$ 35,977	$ (177,005)	$ 154,497
Amount of (Gain) Loss Reclassified from AOCI to Realized Oil and Gas Hedge Gain (Loss) (Effective Portion)	Commodity hedges	$ (67,344)	$ 46,463	$ (15,470)

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 consolidated statements of operations:

Derivatives Qualifying as Cash Flow Hedges	Classification of (Gain) Loss Recognized in Earnings	(Gain) Loss Recognized in Earnings (Ineffective Portion)		
		For the Years Ended December 31,		
		2009	2008	2007
		(In thousands)		
Commodity Hedges	Unrealized derivative (gain) loss	$ 20,469	$(11,209)	$ 4,123

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Derivatives Not Qualifying as Cash Flow Hedges	Classification of (Gain) Loss Recognized in Earnings	(Gain) Loss Recognized in Earnings (Ineffective Portion)		
		For the Years Ended December 31,		
		2009	2008	2007
		(In thousands)		
Commodity Hedges	Unrealized derivative (gain) loss	$ -	$ -	$ 1,335

Interest Rate Derivative Contracts

In September 2007, the Company entered into a one-year floating-to-fixed interest rate derivative contract for a notional amount of $75 million. Under the agreement, the Company paid a fixed rate of 4.90 percent and received a variable rate based on the one-month LIBOR rates. The interest rate derivative contract was measured at fair value using quoted prices in active markets. The interest rate swap was a straightforward, non-complex, non-structured instrument that was highly liquid. A mark-to-market valuation took into consideration anticipated cash flows from the transaction using quoted market prices, other economic data and assumptions, and pricing indications used by other market participants was used to value the swap. Given the degree of varying assumptions used to value the swap, it was deemed as having Level 2 inputs. This derivative qualified for cash flow hedge treatment under ASC Topic 815. The Company recorded a net derivative loss of $1.0 million in the accompanying consolidated statements of operations for the year ended December 31, 2008, related to this interest rate derivative contract. This contract was settled in the third quarter of 2008.

Convertible Note Derivative Instrument

The contingent interest provision of the 3.50% Senior Convertible Notes is a derivative instrument. As of December 31, 2009 and 2008, the value of this derivative was determined to be immaterial.

Note 11 – Fair Value Measurements

On January 1, 2008, the Company applied new authoritative accounting guidance under FASB ASC Topic 820, “Fair Value Measurements and Disclosures” (“ASC Topic 820”) for all financial assets and liabilities measured at fair value on a recurring basis. The topic established a framework for measuring fair value and required enhanced disclosures about fair value measurements. ASC Topic 820 defined 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. The topic established market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The topic established a hierarchy for grouping these assets and liabilities 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

On January 1, 2009, the Company applied ASC Topic 820 to all non-financial assets and liabilities measured at fair value on a nonrecurring basis, including long-lived assets and assets held for sale measured at fair value under ASC Topic 360 and asset retirement obligations initially measured at fair value under FASB ASC Topic 410, "Asset Retirement and Environmental Obligations" ("ASC Topic 410"). The adoption of ASC Topic 820 for non-financial assets and liabilities did not have a material impact on the Company's financial statements.

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, 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 effective January 1, 2009.

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, 2008:

	Level 1	Level 2	Level 3
		(In thousands)	
Assets:			
Derivatives	$ -	$ 133,190	$ -
Liabilities:			
Derivatives	$ -	$ 27,920	$ -
Net Profits Plan	$ -	$ -	$ 177,366

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 and gas 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 St. Mary'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 the requirements of ASC Topic 820 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. If commodity prices fall, the liability is reduced or eliminated.

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 a predominate number of the pools, a discount rate of 12 percent is used to calculate this liability. This rate is 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 price and 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. For 2008 and prior the commodity price assumptions were formulated by applying a price that was derived from a rolling average of actual prices realized in the 24 months prior to the reporting date together with adjusted NYMEX strip prices for the ensuing 12 months. This average price was adjusted to include the effect of hedge prices for the percentage of forecasted production hedged in the relevant periods. Due to significant fluctuations in commodity prices over the past two years the Company no longer believes this method for computing commodity price assumptions produces the best estimate of future prices. The December 31, 2009, Net Profits Plan liability was determined using price assumptions that were computed using five one-year strip prices with the fifth year's pricing being carried out indefinitely. The Company's management believes the change in accounting estimate is appropriate and provides a better estimation of the liability. The average price is still adjusted to include the effects of hedging. 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 and natural gas commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at December 31, 2009, would differ by approximately $14 million. A one percentage point decrease in the discount rate would result in an increase to the liability of approximately $9 million, while a one percentage point increase in the discount rate would result in a decrease to the liability of approximately $8 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,		
	2009	2008	2007
	(In thousands)		
Beginning balance	$ 177,366	$ 211,406	$ 160,583
Net increase in liability (c)	13,511	17,421	82,734
Net settlements (c) (d)	(20,586)	(51,461)	(31,911)
Transfers in (out) of Level 3	-	-	-
Ending balance	$ 170,291	$ 177,366	$ 211,406

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

(d) Settlements represent cash payments made or accrued for under the Net Profits Plan.

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 $290.0 million and $204.0 million as of December 31, 2009 and 2008, respectively. The fair value of the embedded contingent interest derivative as of December 31, 2009, and 2008, was zero.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value if the sum of the expected undiscounted future cash flows is less than net book value pursuant to ASC Topic 360. 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 computed to be 12 percent for the year ended December 31, 2009. 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.

In accordance with ASC Topic 820, of the $2.1 billion worth of long-lived assets, excluding materials inventory, $11.7 million were measured at fair value 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.

In accordance with ASC Topic 820, of the $24.5 million of materials inventory, $13.9 million was measured at fair value at December 31, 2009.

Asset Retirement Obligations

The Company estimates asset retirement obligations pursuant to the provisions of ASC Topic 410. The income valuation technique is utilized by the Company to determine the fair value of the 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, 2009.

Please refer to Note 10 – Derivative Financial Instruments and Note 9 – Asset Retirement Obligations for more information regarding the Company's hedging instruments and asset retirement obligations, as well as Note 8 - Pension Benefits for additional fair value discussion.

Note 12 – 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 St. Mary's existing credit facility agreement 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,		
	2009	2008	2007
Number of shares repurchased	-	2,135,600	792,216
Total purchase price, including commissions	$ -	$ 77,149,451	$ 25,956,847
Weighted-average price, including commissions	$ -	$ 36.13	$ 32.76
Number of shares retired	-	2,945,212	-
Remaining shares authorized to be repurchased	3,072,184	3,072,184	5,207,784

Note 13 – Hurricanes

In 2008 assets in which the Company has an interest were impacted by Hurricanes Gustav and Ike. The Company incurred damage to two wells and to its production facilities located at Goat Island in Galveston Bay and minor damages to several other properties. The Vermilion 281 production platform was lost in Hurricane Ike. The

Company made use of its insurance coverage with regards to the lost platform and damage to several other properties. Due to the severe damage caused by the hurricanes, the total storm related costs exceeded the maximum insurance policy limit. As a result, the Company recorded losses of $8.3 million and $7.0 million in other expense in the accompanying consolidated statements of operations for the years ended December 31, 2009 and 2008, respectively. To date, the Company has received $16.8 million in insurance proceeds. Any variation between actual and estimated storm related costs will impact the final determination of the loss.

In April 2007 the Company reached a global insurance settlement for reimbursement of damages sustained during Hurricane Rita in 2005. St. Mary's net cash received in the final settlement was approximately $33 million. The Company recorded a loss of $2.3 million and a gain of $5.2 million in other revenue in the accompanying consolidated statements of operations for the years ended December 31, 2008, and 2007, respectively, resulting in a total net gain of $2.9 million. The Company's retirement efforts were complete as of December 31, 2008.

Note 14 – SemGroup Bankruptcy

On July 22, 2008, SemGroup, L.P. and certain of its North American subsidiaries (collectively referred to herein as "SemGroup") filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. At that time, certain SemGroup entities purchased a portion of the Company's crude oil production. As a result of the SemGroup bankruptcy filing the Company recorded an allowance for doubtful accounts and bad debt expense of $16.6 million as of December 31, 2008.

On October 27, 2009, the Company executed a Purchase and Sale Agreement whereby the Company sold a portion of its SemGroup administrative claim under Section 503(b)(9) of the Bankruptcy Code. The Company recorded a recovery of bad debt expense within the accompanying consolidated statements of operations for the year ended December 31, 2009. The Company deemed the remaining accounts receivable balance relating to SemGroup to be uncollectible. As a result of this determination, the Company wrote off the allowance for doubtful accounts and the accounts receivable balance as of December 31, 2009. This matter is complete as of December 31, 2009, and did not have a material adverse effect on the Company's liquidity or overall financial position.

Note 15 – 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,		
	2009	2008	2007
	(In thousands)		
Development costs	$ 223,108	$ 587,548	$ 592,275
Exploration costs	154,122	92,199	111,470
Acquisitions			
Proved properties	76	51,567	161,665
Unproved properties – acquisitions of proved properties (1)	-	43,274	23,495
Unproved properties - other	41,677	83,078	38,436
Total, including asset retirement obligation(2)(3)	$ 418,983	$ 857,666	$ 927,341

(1) Represents the allocated purchase price of unproved properties acquired as part of the acquisition of proved properties. Refer to Note 3 – Acquisitions, Divestitures, and Assets Held for Sale for additional information.

(2) Includes capitalized interest of $1.9 million, $4.7 million, and $6.7 million for the years ended December 31, 2009, 2008, and 2007, respectively.

(3) Includes amounts relating to estimated asset retirement obligations of $(805,000), $15.4 million, and $27.6 million for the years ended December 31, 2009, 2008, and 2007, respectively.

Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2009, 2008, and 2007. 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,		
	2009	2008	2007
	(In thousands)		
Beginning balance on January 1,	$ 9,437	$ 42,930	$ 22,799
Additions to capitalized exploratory well costs pending the determination of proved reserves	34,384	9,437	29,551
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(7,569)	(36,842)	(9,237)
Capitalized exploratory well costs charged to expense	(1,868)	(6,088)	(183)
Ending balance at December 31,	$ 34,384	$ 9,437	$ 42,930

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,		
	2009	2008	2007
	(In thousands)		
Exploratory well costs capitalized for one year or less	$ 34,384	$ 9,437	$ 29,368
Exploratory well costs capitalized for more than one year	-	-	13,562
Ending balance at December 31,	$ 34,384	$ 9,437	$ 42,930
Number of projects with exploratory well costs that have been capitalized more than a year	-	-	3

Note 16 – Disclosures about Oil and Gas Producing Activities (Unaudited)

Recent SEC and FASB Guidance

In December 2008 the SEC published the final rules and interpretations updating its oil and gas reporting requirements. The Company adopted the rules effective December 31, 2009, and the rule changes, including those related to pricing and technology, are included in the Company's reserve estimates.

In January 2010 the FASB aligned ASC Topic 932, with the aforementioned SEC requirements. Please refer to the section entitled Recently Issued Accounting Standards under Note 1 – Summary of Significant Accounting Policies for additional discussion regarding both adoptions.

Application of the new rules resulted in the use of lower prices at December 31, 2009, for both oil and gas than would have resulted under the SEC's previous methodology. Using 12-month average commodity prices the Company's estimated proved reserves were 772.2 BCFE at December 31, 2009, compared to estimated proved reserves of 865.5 at December 31, 2008. Using year-end commodity prices, as required under the SEC's previous methodology, would have resulted in estimated proved reserves of 897.2 BCFE at December 31, 2009. Therefore, the total impact of the new SEC price methodology was a negative 125 BCFE.

Third-party Reserves Audit

The Company engaged Ryder Scott Company, L.P. to review internal engineering estimates for at least 80 percent of the PV-10 value of our proven conventional oil and gas reserves in 2009, 2008, and 2007. For 2008 and 2007, Netherland, Sewell and Associates, Inc. prepared the reserve information for the Company's coalbed methane projects at Hanging Woman Basin in the northern Powder River Basin and St. Mary's non-operated coalbed methane interest in the Green River Basin. The Company divested of all Hanging Woman Basin properties in the fourth quarter of 2009. Please refer to the section entitled Third-party Reserves Audit under the heading Reserves included in Part I, Items 1. and 2. Business and Properties.

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 the continental United States.

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:

	For the Years Ended December 31,					
	2009		2008		2007	
	Oil or Condensate (MBbl)	Gas (MMcf)	Oil or Condensate (MBbl)	Gas (MMcf)	Oil or Condensate (MBbl)	Gas (MMcf)
Total Proved Reserves						
Beginning of year	51,363	557,366	78,847	613,450	74,195	482,475
Revisions of previous estimate(a)	4,520	(76,767)	(22,667)	(108,163)	5,238	9,489
Discoveries and extensions	3,389	51,964	677	41,077	1,166	28,483
Infill reserves in an existing proved field	1,241	29,855	5,424	92,389	4,592	69,090
Purchases of minerals in place	-	-	356	26,956	567	91,374
Sales of reserves (b)	(401)	(41,767)	(4,659)	(33,433)	(4)	(1,400)
Production	(6,328)	(71,106)	(6,615)	(74,910)	(6,907)	(66,061)
End of year (c)	53,784	449,545	51,363	557,366	78,847	613,450
Proved developed reserves						
Beginning of year	47,106	433,210	68,277	426,627	61,519	358,477
End of year	48,045	342,044	47,106	433,210	68,277	426,627
Proved undeveloped reserves						
Beginning of year	4,257	124,156	10,570	186,823	12,676	123,998
End of year	5,739	107,501	4,257	124,156	10,570	186,823

(a) 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. Well performance data collected during 2009 at the Sweetie Peck and Halff East programs that target the Wolfberry interval indicate that these assets are underperforming for year-end 2008 decline forecasts. Accordingly, the Company removed 37 BCFE from proved reserves in the Permian region, primarily related to the Wolfberry tight oil program. The Company believes that a significant portion of these reserves, while not meeting the criteria to be booked as proved reserves at year-end, are likely to eventually be produced. The Company also saw a downward performance revision of 12 BCFE 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. For the year ended December 31, 2007, of the 40.9 BCFE upward revision of previous estimate, 34.5 BCFE and 6.4 BCFE relate to price and performance revisions, respectively.

(b) The Company divested of certain non-core assets during 2009, 2008, and 2007. Please refer to Note 3 - Acquisitions, Divestitures, and Assets Held for Sale for additional information.

(c) For the years ended December 31, 2009, 2008, and 2007, amounts included approximately 370, 659, and 316 MMcf respectively, representing the Company's net underproduced gas balancing position.

Standardized Measure of Discounted Future Net Cash Flows

The Company follows the guidelines prescribed in ASC Topic 932 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:

	2009	2008	2007
Gas (per Mcf)	$ 3.82	$ 4.88	$ 7.56
Oil (per Bbl)	$ 53.94	$ 33.91	$ 88.71

The following summary sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in ASC Topic 932:

	As of December 31,		
	2009	2008	2007
	(In thousands)		
Future cash inflows	$ 4,620,735	$ 4,463,894	$ 11,629,679
Future production costs	(1,968,096)	(1,866,821)	(3,672,857)
Future development costs	(387,722)	(393,620)	(611,288)
Future income taxes	(515,953)	(419,544)	(2,316,637)
Future net cash flows	1,748,964	1,783,909	5,028,897
10 percent annual discount	(732,997)	(724,840)	(2,321,983)
Standardized measure of discounted future net cash flows	$ 1,015,967	$ 1,059,069	$ 2,706,914

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

	For the Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Standard measure, beginning of year	$ 1,059,069	$ 2,706,914	$ 1,576,436
Sales of oil and gas produced, net of production costs	(409,153)	(988,045)	(693,885)
Net changes in prices and production costs	154,008	(2,033,674)	1,320,994
Extensions, discoveries and other including infill reserves in an existing proved field, net of production costs	166,666	288,162	462,952
Purchase of minerals in place	-	33,215	265,285
Development costs incurred during the year	33,742	105,031	123,630
	75,134	213,554	(32,566)

Changes in estimated future development costs			
Revisions of previous quantity estimates	(96,354)	(363,908)	166,428
Accretion of discount	126,538	386,118	215,745
Sales of reserves in place	(44,823)	(198,514)	(1,915)
Net change in income taxes	(61,801)	947,955	(573,259)
Changes in timing and other	12,941	(37,739)	(122,931)
Standardized measure, end of year	$ 1,015,967	$ 1,059,069	$ 2,706,914

Note 17 – Quarterly Financial Information (Unaudited)

The Company's quarterly financial information for fiscal 2009 and 2008 is as follows (in thousands, except per share amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
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	$ -
Year Ended December 31, 2008 (1)				
Total operating revenues	$ 362,102	$ 356,942	$ 324,088	$ 258,169
Total operating expenses	204,762	298,691	179,762	446,885
Income (loss) from operations	$ 157,340	$ 58,251	$ 144,326	$ (188,716)
Income (loss) before income taxes	$ 150,844	$ 51,067	$ 137,539	$ (194,714)
Net income (loss)	$ 94,974	$ 32,469	$ 86,997	$ (127,092)
	$ 1.51	$ 0.53	$ 1.40	$ (2.04)

Basic net income (loss) per common share								
Diluted net income (loss) per common share	$	1.48	$	0.52	$	1.38	$	(2.04)
Dividends declared per common share	$	0.05	$	-	$	0.05	$	-

(1) The 2008 amounts have been adjusted for the application of guidance under ASC Topic 470.

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.

	ST. MARY LAND & EXPLORATION COMPANY (Registrant)	
Date: February 23, 2010	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, 2009, 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, Chief Executive Officer, and Director	February 23, 2010
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer	February 23, 2010
/s/ MARK T. SOLOMON Mark T. Solomon	Controller	February 23, 2010

Signature	Title	Date
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Chairman of the Board of Directors	February 23, 2010
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 23, 2010
/s/ LARRY W. BICKLE Larry W. Bickle	Director	February 23, 2010
/s/ WILLIAM J. GARDINER William J. Gardiner	Director	February 23, 2010
/s/ JULIO M. QUINTANA Julio M. Quintana	Director	February 23, 2010
/s/ JOHN M. SEIDL John. M. Seidl	Director	February 23, 2010