GULFPORT ENERGY CORP
Form 10-K
February 27, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011

OR

¨ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 000-19514

Gulfport Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**73-1521290**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**
14313 North May Avenue, Suite 100	
Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	**(Zip code)**

(405) 848-8807

(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, par value $0.01 per share	**The NASDAQ Stock Market LLC**

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

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

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

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

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 (Section 232.405 of this chapter) during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) 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. x

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 definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 30, 2011, based on the closing price of the common stock on the NASDAQ Global Select Market on June 30, 2011, the last business day of the registrant s most recently completed second fiscal quarter ($29.69 per share) was $1,134,495,605.

As of February 20, 2012, 55,621,371 shares of the registrant s common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation s Proxy Statement for the 2012 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

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FORWARD-LOOKING STATEMENTS

Our disclosure and analysis in this Form 10-K may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements by terms such as may, will, should, could, would, expects, plans, anticipates, intends, believes, estimates, proj and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements.

These forward-looking statements are largely based on our expectations and beliefs concerning future events, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control.

Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations sections and elsewhere in this Form 10-K. All forward-looking statements speak only as of the date of this Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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PART I

ITEM 1. BUSINESS

General

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. During 2010, we acquired our initial acreage position in the Niobrara Formation of northwestern Colorado and, during 2011, we acquired our initial acreage position in the Utica Shale in Eastern Ohio. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

In 2011, at our WCBB field, we recompleted 68 wells and drilled 21 wells for a total cost of approximately $42.4 million as of December 31, 2011. Of the 21 new wells drilled at WCBB in 2011, 19 were completed as producing wells, one was non-productive and one was waiting on completion. In the fourth quarter of 2011, production at WCBB was 362,996 net barrels of oil equivalent, or BOE, or an average of 3,946 BOE per day, 96% of which was from oil and 4% of which was from natural gas. From January 1, 2012 through January 31, 2012, our average net daily production at WCBB was 3,705 BOE, 96% of which was from oil and 4% of which was from natural gas. During 2012, we currently anticipate drilling 22 to 24 wells and recompleting 60 wells at our WCBB field for an estimated aggregate cost of $36.0 million to $38.0 million.

In 2011, at our East Hackberry field, we recompleted 24 wells and drilled 22 wells for a total cost of approximately $51.9 million as of December 31, 2011. Of the 22 new wells drilled at East Hackberry during 2011, 17 were completed as producing wells, two were non-productive and three were waiting on completion. In the fourth quarter of 2011, net production at East Hackberry was 190,930 BOE, or an average of 2,075 BOE per day, 97% of which was from oil and 3% of which was from natural gas. From January 1, 2012 through January 31, 2012, our average net daily production at East Hackberry was 2,220 BOE, 99% of which was from oil and 1% of which was from natural gas. During 2012, we currently anticipate drilling 10 to 12 wells and recompleting 10 wells for an aggregate estimated cost of $24.0 million to $26.0 million.

In the fourth quarter of 2011, net production at West Hackberry was 3,279 BOE, or an average of 36 BOE per day, 100% of which was from oil. From January 1, 2012 through January 31, 2012, our average net daily production at West Hackberry was 37 BOE, 100% of which was from oil.

In 2011, 39 gross (17 net) wells were drilled and eight gross (four net) wells were recompleted on our Permian Basin acreage for a total net cost of $38.4 million. As of December 31, 2011, 35 of the 39 wells had been completed and four wells were awaiting completion. In the fourth quarter of 2011, net production from our Permian Basin acreage was 93,760 BOE, or an average of 1,019 BOE per day, of which approximately 74% was from oil, 13% was from natural gas liquids and 13% was from natural gas. From January 1, 2012 through January 31, 2012, our average daily net production from our Permian Basin acreage was 1,032 BOE, of which 72% was from oil, 16% was from natural gas liquids and 12% was from natural gas. We currently anticipate that 23 to 25 gross (11.5 to 12.5 net) wells will be drilled and five gross (2.5 net) wells will be recompleted on this acreage in 2012 for an estimated aggregate net cost of $23.0 million to $25.0 million. In an effort to facilitate the development of our Permian Basin and other domestic acreage, we acquired a 25% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates four drilling rigs. The remaining 75% equity interest is owned by entities controlled by Wexford Capital LP, or Wexford. An affiliate of Wexford owned approximately 13.3% of our outstanding common stock as of February 20, 2012. We have also purchased a 25% interest in Muskie Holdings LLC, or Muskie, which holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. Muskie is controlled by Wexford.

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in northwestern Colorado and held leases for approximately 15,000 net acres as of December 31, 2011. During the year ended December 31, 2011, we drilled three gross (1.5 net) wells on this acreage. In the fourth quarter of 2011, net production from our Niobrara acreage was 3,390 BOE, or an average of 37 BOE per day, 100% of which was from oil. From January 1, 2012 through January 31, 2012, our average net daily production from our Niobrara acreage was 41 BOE, 100% of which was from oil. In the Niobrara Formation, we have completed a 60 square mile 3-D seismic survey, have received a processed version of the seismic and are selecting future drilling locations. During 2012, we currently anticipate drilling five to seven gross wells in the Niobrara Formation for approximately $5.0 million to $6.0 million.

As of December 31, 2011, we held approximately 800 net acres in the Williston Basin of western North Dakota and eastern Montana with interests in six wells and an overriding royalty interest in wells drilled prior to our 2009 sale of certain of our Bakken acreage and production from such acreage, wells drilled subsequent to such sale and wells that might be drilled in the future. In the fourth quarter of 2011, our net production from this acreage was 7,167 BOE, or an average of 78 BOE per day, of which 91% was from oil, 6% was from natural gas and 3% was from natural gas liquids. From January 1, 2012 through January 31, 2012, our average daily net production from our Bakken acreage was 71 BOE, of which 92% was from oil and 8% was from natural gas.

As of December 31, 2011, we had acquired leasehold interests in approximately 98,000 gross (49,000 net) acres in the Utica Shale in Eastern Ohio. As of February 20, 2012, we had closed on additional acquisitions bringing our leasehold interests to approximately 107,000 gross (53,500 net) acres. We intend to continue to pursue opportunities in this area and have commitments with various future closing dates that could increase our acreage position in the Utica Shale to an aggregate of approximately 125,000 gross (62,500 net) leasehold acres. We recently spud our first well on our Utica Shale acreage.

During the third quarter of 2006, we, through our wholly-owned subsidiary Grizzly Holdings Inc., purchased a 24.9% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford. As of December 31, 2011, Grizzly had approximately 754,000 acres under lease in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. As of December 31, 2011, Grizzly had drilled an aggregate of 203 core holes and four water supply test wells, tested nine separate lease blocks and conducted a seismic program. In March 2010, Grizzly filed an application for the development of an 11,300 barrel per day oil sand project at Algar Lake. In November 2011, the Government of Alberta provided a formal Order-in Council authorizing the Alberta Energy Resources Conservation Board (ERCB) to issue the formal regulatory approval of Grizzly s Algar Lake SAGD project. Grizzly s currently contemplated 2012 activities include the completion of the 2011/2012 core hole drilling and seismic program, submission of a SAGD project regulatory application for Thickwood Hills and the development of its Algar Lake SAGD project, which includes the fabrication and onsite construction of a central processing facility and the drilling of ten initial SAGD well pairs.

We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II. The remaining interests in Tatex II are owned by entities controlled by Wexford. Tatex II, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately two million acres which includes the Phu Horm Field.

We also own a 17.9% ownership interest in Tatex Thailand III, LLC, or Tatex III. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Tatex III owns a concession covering approximately one million acres. In 2009, Tatex III completed a 3-D seismic survey on this concession. The first well was drilled on our concession in 2010 and was temporarily abandoned pending further scientific evaluation. Drilling of the second well concluded in March 2011. The second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. The well experienced gas shows and carried a flare measuring up to 25 feet throughout drilling below the intermediate casing point of 9,695 feet. During testing, the well produced at rates as high as 16 million cubic feet per day of

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gas for short intervals, but would subsequently fall to a sustained rate of 2 million cubic feet per day. Pressure buildup information confirmed that this wellbore lacked the permeability to deliver commercial quantities of gas. Despite an apparently well-developed porosity system suggesting potential for a large amount of gas in place, testing of the well did not exhibit that there was sufficient permeability to produce in commercial quantities. Tatex III intends to continue testing some of the structures identified through its 3-D seismic survey and has begun the application process for two more drilling locations. Tatex III currently expects to drill the first, located to the south of the TEW-E well, late this year or early 2013.

As of December 31, 2011, we had 19.4 million barrels of oil equivalent, or MMBOE, of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately $490.5 million and associated standardized measure of discounted future net cash flows of approximately $376.7 million, excluding reserves attributable to our interests in Grizzly, Tatex II and Tatex III. See Item 2. Properties Proved Oil and Natural Gas Reserves for our definition of PV-10, a non-GAAP financial measure, and a reconciliation of our standardized measure of discounted future net cash flows to PV-10.

Principal Oil and Natural Gas Properties

The following table presents certain information as of December 31, 2011 reflecting our net interest in our principal producing oil and natural gas properties along the Louisiana Gulf Coast, in the Permian Basin in West Texas, in the Niobrara Formation in northwestern Colorado and in the Williston Basin in western North Dakota and eastern Montana.

								Proved Reserves		
		Productive Wells (2)		Non-Productive Wells		Developed Acreage (3)				
Field	NRI/WI (1) Percentages	Gross	Net	Gross	Net	Gross	Net	Gas MBOE	Oil MBOE	Total MBOE
West Cote Blanche Bay Field (4)	80.108/100	95	95	189	189	5,668	5,668	352	3,617	3,969
E. Hackberry Field (5)	79.424/100	30	30	93	93	3,291	3,291	226	1,606	1,832
W. Hackberry Field	87.5/100	2	2	23	23	592	592		76	76
Permian Basin	35.4/46.87	121	57			8,880	4,119	2,008	10,877	12,885
Niobrara Formation	39.7/47.9	6	3	2	1	3,954	1,977	26	500	526
Williston Basin (6)	2.8/3.3	6	.2			1,708	132	7	67	74
Overrides/Royalty Non-operated	Various	133	.2					3	2	5
Total		393	187.4	307	306	24,093	15,779	2,622	16,745	19,367

(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes six gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 36% of our acreage is developed acreage and has been perpetuated by production.
(4) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(5) NRI shown is for producing wells.
(6) NRI/WI is from wells that have been drilled or in which we have elected to participate.

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West Cote Blanche Bay Field

Location and Land

The WCBB field is located approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. We own a 100% working interest (80.108% net revenue interest, or NRI), and are the operator, in depths above the base of the 13900 Sand which is located at 11,320 feet. In addition, we own a 40.40% non-operated working interest (29.95% NRI) in depths below the base of the 13900 Sand, which is operated by Chevron Corporation. Our leasehold interests at WCBB contain 5,668 gross acres.

Area History and Production

Texaco, now Chevron Corporation, drilled the discovery well in this field in 1940 based on a seismic and gravitational anomaly. WCBB was subsequently developed on an even 160-acre pattern for much of the remainder of the decade. Developmental drilling continued and reached its peak in the 1970s when over 300 wells were drilled in the field. Of the 994 wells drilled as of December 31, 2011, 900 were completed as producing wells. As a result, the field has a historic success rate of 91% for all wells drilled. From the date of our acquisition of WCBB in 1997 through December 31, 2011, we drilled 183 new wells, 166 of which were productive, for a 91% success rate. As of December 31, 2011, estimated field cumulative gross production was 192.6 MMBOE and 236.6 billion cubic feet, or Bcf, of gas. Of the 994 wells drilled in WCBB as of December 31, 2011, 89 were producing, 189 were shut-in, six were producing intermittently and five were being used as salt water disposal wells. The other 705 wells have been plugged and abandoned.

In 1991, Texaco conducted a 70 square mile 3-D seismic survey with 1,100 shot points per mile that processed out 100 fold. In 1993, an undershoot survey around the crest and production facilities was completed. We own the rights to the seismic data. In December 1999, we completed the reprocessing of the seismic data and our technical staff developed prospects from the data. The reprocessed data has enabled us to identify prospects in areas of the field that would have otherwise remained obscure. During the first half of 2005, we again reprocessed the seismic data using advanced seismic data processing.

Geology

WCBB overlies one of the largest salt dome structures on the Gulf Coast. The field is characterized by a piercement salt dome, which created traps from the Pleistocene through the Miocene formations. The relative movements affected deposition and created a complex system of fault traps. The compensating fault sets generally trend northwest to southeast and are intersected by sets having a major radial component. Later-stage movement caused extension over the dome and a large graben system (a downthrown area bounded by normal faults) was formed.

There are over 100 distinct sandstone reservoirs recognized throughout most of the field, and nearly 200 major and minor discrete intervals have been tested. Within the 994 wells that had been drilled in the field as of December 31, 2011, over 4,000 potential zones have been penetrated. These sands are highly porous and permeable reservoirs primarily with a strong water drive.

WCBB is a structurally and stratigraphically complex field. All of the proved undeveloped, or PUD, locations at WCBB are adjacent to faults and abut at least one fault. Our drilling programs are designed to penetrate each PUD trap with a new wellbore in a structurally optimum position, usually very close to the fault seal. The majority of these wells have been, and new wells drilled in connection with our drilling programs will be, directionally drilled using steering tools and downhole motors. The tolerance for error in getting near the fault is low, so the complex faulting does introduce the risk of crossing the fault before encountering the zone of interest, which could result in part or all of the zone being absent in the borehole. This, in turn, can result in lower than expected or no reserves for that zone. The new wellbores eliminate the mechanical risk associated with trying to produce the zone from an old existing wellbore, while the wellbore locations are selected in an effort to more efficiently drain each reservoir. The vast majority of the PUD targets are up-dip offsets to wells that produced from a sub-optimal position within a particular zone. Our inventory of prospects at WCBB as of December 31, 2011 included 24 PUD wells. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2015.

Facilities

We own and operate a production facility at WCBB that includes four production tank batteries, eight natural gas compressors, a storage barge facility, a dock, a dehydration unit and a salt water disposal system.

Recent and Future Activity

In 2011, we recompleted 68 gross and net wells and drilled 21 gross and net wells at WCBB. Nineteen of the new wells were completed as producers, one was non-productive and one was waiting on completion. As of February 20, 2012, we had drilled three wells, were in the process of drilling two additional wells and recompleted six wells during 2012. Of the 21 wells drilled in 2011, 18 were considered deep wells. The 19 productive wells, with total depths ranging from 2,500 to 10,748 feet, have approximately 1,855 feet of aggregate apparent net pay. We currently anticipate drilling 22 to 24 gross and net wells and recompleting 60 gross and net wells at WCBB during 2012.

Production Status

In the fourth quarter of 2011, our production at WCBB was 362,996 net BOE, or an average of 3,946 BOE per day, 96% of which was from oil and 4% of which was from natural gas. From January 1, 2012 through January 31, 2012, our average net daily production at WCBB was 3,705 BOE, 96% of which was from oil and 4% of which was from natural gas. The decrease in production was due to normal production declines.

East Hackberry Field

Location and Land

The East Hackberry field in Louisiana is located along the western shore and the land surrounding Lake Calcasieu, 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 79.424% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. We hold beneficial interests in approximately 3,291 acres, including the Erwin Heirs Block, which is located on land, and the adjacent State Lease 50 Block, which is located primarily in the shallow waters of Lake Calcasieu. We also hold 2,868 net acres subject to a two-year exploration agreement we entered into with an active gulf coast operator. We are the designated operator under the agreement and will participate in proposed wells with at least a 70% working interest. We have licensed approximately 54 square miles of 3-D seismic data covering a portion of the area and are reprocessing the data.

Area History and Production

The East Hackberry field was discovered in 1926 by Gulf Oil Company, now Chevron Corporation, by a gravitational anomaly survey. The massive shallow salt stock presented an easily recognizable gravity anomaly indicating a productive field. Initial production began in 1927 and has continued to the present. The estimated cumulative oil and condensate production through 2011 was over 1,625 MBOE and 330 Bcf of casinghead gas production. A total of 223 wells have been drilled on our portion of the field. As of December 31, 2011, 30 wells had daily production, 93 were shut-in and two had been converted to salt water disposal wells. The remaining 98 wells had been plugged and abandoned.

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Geology

The Hackberry field is a major salt intrusive feature, elliptical in shape as opposed to a classic dome, divided into east and west field entities by a saddle. Structurally, our East Hackberry acreage is located on the eastern end of the Hackberry salt ridge. There are over 30 pay zones at this field. The salt intrusion formed a series of structurally complex and steeply dipping fault blocks in the Lower Miocene and Oligocene age rocks. These fault blocks serve as traps for hydrocarbon accumulation. Our wells currently produce from perforations found between 5,100 and 12,200 feet.

Facilities

We have a field office that serves both the East and West Hackberry fields. In addition, we own and operate two production facilities at East Hackberry that include a land based tank battery, production barge, three natural gas compressors, dehydration units and salt water disposal systems.

Recent and Future Activity

During 2005, we completed a proprietary 42 square mile 3-D seismic survey at East Hackberry, the first modern seismic program undertaken at this field. We believe that this 3-D seismic data enhances our probability of drilling success, and we continue to evaluate the 3-D seismic data to identify additional drilling locations. During 2011 at East Hackberry, we recompleted 24 gross and net wells and drilled 13 gross and net land wells and nine gross and net wells on water. Seventeen of the 22 wells drilled during 2011 were completed as producing wells, two were non-productive and three were waiting on completion. As of February 20, 2012, we had recompleted two wells during 2012, drilled two wells and were in the process of drilling two additional wells. We currently intend to drill 10 to 12 gross and net wells and recomplete 10 gross and net wells at East Hackberry during 2012.

Production Status

In the fourth quarter of 2011, our net production at East Hackberry was 190,930 BOE, or an average of 2,075 BOE per day, 97% of which was from oil and 3% of which was from natural gas. From January 1, 2012 through January 31, 2012, our average net daily production at East Hackberry was 2,220 BOE, 99% of which was from oil and 1% of which was from natural gas. The increase in production in 2012 is a result of our 2012 drilling activities.

West Hackberry Field

Location and Land

The West Hackberry field is located on land and is five miles west of Lake Calcasieu in Cameron Parish, Louisiana, approximately 85 miles west of Lafayette and 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 87.5% NRI) in 592 acres within the West Hackberry field. Our leases at West Hackberry are located within two miles of one of the United States Department of Energy s Strategic Petroleum Reserves.

Area History

The first discovery well at West Hackberry was drilled in 1938 and the field was developed by Superior Oil Company, now ExxonMobil Corporation, between 1938 and 1988. The estimated cumulative oil and condensate production through 2011 was 286 MBOE and 140 Bcf of natural gas. There have been 36 wells drilled to date on our portion of West Hackberry. Currently, two are producing, 23 are shut-in and one has been converted to a saltwater disposal well. The remaining 10 wells have been plugged and abandoned.

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Geology

Structurally, our West Hackberry acreage is located on the western end of the Hackberry salt ridge. There are over 30 pay zones at this field. West Hackberry consists of a series of fault-bounded traps in the Oligocene-age Vincent and Keough sands associated with the Hackberry Salt Ridge. Recoveries from these thick, porous, water-drive reservoirs have resulted in per well cumulative production of almost 700 MBOE.

Production Status

In the fourth quarter of 2011, our net production at West Hackberry was 3,279 BOE, or an average of 36 BOE per day. From January 1, 2012 through January 31, 2012, our average net daily production at West Hackberry was 37 BOE and was 100% oil.

Facilities

We own and operate a production facility at West Hackberry that includes a land based tank battery and salt water disposal system.

Permian Basin (West Texas)

Location and Land

We acquired approximately 4,100 net acres and 32 gross (16 net) producing wells in West Texas (near Midland) in the Permian Basin effective November 1, 2007. Subsequently, we acquired approximately 11,200 additional net acres, which brought our total net acreage position in the Permian Basin to approximately 15,300 net acres as of December 31, 2011. The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States. The terrain in the Permian Basin is semi-arid mesquite-mixed grassland steppe. Windsor Permian LLC, or Windsor, an entity controlled by Wexford, is the operator of this field.

Area History

The Permian Basin formed as an area of rapid Mississippian-Pennsylvanian subsidence in the foreland of the Ouachita Foldbelt. The Wolfcamp play was a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or reef facies with reservoir properties. Exploration with 2-D seismic located additional fields, but it was not until the use of 3-D seismic in the 1990s that the greater extent of the Wolfcamp prospects was revealed. During the late 1990s, Arco began a drilling program targeting the Spraberry formation at 10,000 feet and then drilled another 200 to 300 feet to pick up the upper part of the Wolfcamp formation. Henry Petroleum, a private firm, owned interest in the Pegusas field in Midland and Upton counties. While drilling in the same area as the Arco project, Henry Petroleum decided to drill completely through the Wolfcamp section as Devonian wells. Henry Petroleum mapped the trend and began acquiring acreage and drilling wells using multiple slick-water fracs across the entire Wolfcamp interval. In 2005, former members of Henry Petroleum s Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry Petroleum s program. After ExL had drilled 32 productive Wolfcamp/Spraberry wells through late 2007, they decided to monetize approximately 15% of their acreage position which enabled us to participate in this play. Recent advancements in enhanced recovery techniques continue to make the basin an active play for exploration and production companies. As of December 31, 2011, we held interests in 121 gross (57 net) producing wells.

Geology

The Wolfcamp/Spraberry play, which we refer to as Wolfberry, of the Midland Basin lies in the area where the historically productive Spraberry trend geographically overlaps the productive area of the emerging

Wolfcamp carbonate play. The Wolfcamp is characterized by an approximately 2,000 feet section of organic rich basin floor debris flows shed from the Central Basin Platform. The best reservoir rock within the section is generally found in close proximity to the Central Basin Platform.

Wolfberry well reserves are typically approximately 80% from the Wolfcamp section and 20% from the Spraberry section. Ryder Scott Company L.P., or Ryder Scott, an independent petroleum engineering firm, has estimated that at December 31, 2011, proved reserves net to our interest in these assets were approximately 12.9 million BOE, of which 23% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 252 gross well locations on 40-acre units. The proved reserves are located in the Wolfcamp and Spraberry formations, which are generally characterized as long-lived, with predictable production profiles.

Production Status

In the fourth quarter of 2011, our net production from the Permian Basin field was 93,760 BOE, or an average of 1,019 BOE per day, of which 74% was from oil, 13% was from natural gas liquids and 13% was from natural gas. From January 1, 2012 through January 31, 2012, our average daily net production from our Permian Basin acreage was 1,032 BOE, 88% of which was from oil and natural gas liquids and 12% of which was from natural gas.

Facilities

There are typical land oil and natural gas processing facilities in the Permian Basin. Our facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activity

In 2011, 39 gross (17 net) wells were drilled in our Permian Basin acreage. From January 1, 2012 to February 20, 2012, two gross (one net) wells had been drilled on this acreage and were waiting on completion and at February 20, 2012 one gross (0.5 net) additional well was being drilled. We have identified 252 gross future development drilling locations. We currently expect an estimated 23 to 25 gross (11.5 to 12.5 net) wells to be drilled on our acreage in 2012. The wells are expected to be drilled to approximately 11,200 feet. In an effort to facilitate the drilling of these and future wells, in 2011 we acquired a 25% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates four drilling rigs. We acquired our interest in Bison from Windsor Permian LLC, or Windsor. Windsor is the operator of our Permian Basin properties and is controlled by Wexford. An affiliate of Wexford owned approximately 13.3% of our outstanding common stock as of February 20, 2012. During 2011, we also purchased a 25% interest in Muskie Holdings LLC, or Muskie, which holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. Muskie is controlled by Wexford.

Niobrara Formation (Northwestern Colorado)

Location and Land

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in northwestern Colorado, and held leases for 14,993 acres as of December 31, 2011. We are the operator on the acreage.

Area History

The Niobrara Formation is a shale oil rock formation located in Colorado, Northwest Kansas, Southwest Nebraska, and Southeast Wyoming. Oil and natural gas can be found at depths of 3,000 to 14,000 feet and is drilled both vertically and horizontally. The Upper Cretaceous Niobrara formation has emerged as another potential crude oil resource play in various basins throughout the northern Rocky Mountain region. As with most resource plays, the Niobrara has a history of producing through conventional technology with some of the earliest production dating back to the early 1900s. Natural fracturing has played a key role in producing the Niobrara historically due to the low porosity and low permeability of the formation. Because of this, conventional production has been very localized and limited in area extent. We believe the Niobrara can be produced on a more widespread basis using today s horizontal multi-stage fracture stimulation technology where the Niobrara is thermally mature.

Geology

The Niobrara Formation oil play in northwestern Colorado is located between the Piceance Basin to the south and the Sand Wash Basin to the north. Rocks mainly consist of interbedded organic-rich shales, calcareous shales and marlstones. It is the fractured marlstone intervals locally known as the Buck Peak, Tow Creek and Wolf Mountain benches that account for the majority of the areas production. These fractured carbonate reservoirs are associated with anticlinal, synclinal and monoclinal folds, and fault zones. This proven oil accumulation is considered to be continuous in nature and lightly explored. Source rocks are predominantly oil prone and thermally mature with respect oil generation. The producing intervals are geologically equivalent to the Niobrara reservoirs of the DJ and Powder River Basins which are currently emerging as a major crude resource play.

Production Status

In the fourth quarter of 2011, our net production from our Niobrara acreage was 3,390 BOE, or an average of 37 BOE per day, 100% of which was from oil. From January 1, 2012 through January 31, 2012, our average daily net production from our Niobrara acreage was 41 BOE, 100% of which was from oil.

Facilities

There are typical land oil and gas processing facilities in the Niobrara Formation. Our facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activity

We drilled three gross (1.5 net) wells at Niobrara during 2011. We have completed a 60 square mile 3-D seismic survey over our Craig Dome prospect, have received a processed version of the seismic and are selecting future drilling locations. We currently intend to drill five to seven gross wells at Niobrara during 2012.

Bakken

Location and Land

The Bakken Shale is located in the Williston Basin areas of western North Dakota and eastern Montana. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken were owned by entities controlled by Wexford. Beginning in 2005, Bakken acquired leases on undeveloped acreage in the Williston Basin. As of December 31, 2007, Bakken had commenced participating in the drilling of some of its undeveloped acreage. Effective January 1, 2008, we acquired a direct, undivided 20% interest in Bakken s assets in redemption of our 20% interest in Bakken. During May 2009, we sold approximately 12,270 net acres and approximately 190 net BOEPD of production for approximately $13.0 million, with an effective date of April 1, 2009. During September 2009, we sold approximately 5,721 net acres for approximately $5.8 million with an effective date of July 1, 2009. As of December 31, 2011, we held approximately 800 net acres, interests in six wells and an overriding royalty interest in wells drilled prior to our 2009 sale, wells drilled subsequent to such sale and wells that might be drilled in the future.

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Production Status

In the fourth quarter of 2011, our net production from our Bakken acreage was 7,167 BOE, or an average of 78 BOE per day, of which 91% was from oil, 3% was from natural gas liquids and 6% was from natural gas. From January 1, 2012 through January 31, 2012, our average net daily production from this acreage was 71 BOE, of which 92% was from oil and 8% was from natural gas.

Facilities

There are typical land oil and gas processing facilities in the Williston Basin. The facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and future activities

One gross (.01 net) well was drilled on our acreage in 2011. There are no new activities currently scheduled for 2012 for our Bakken acreage.

Utica Shale (Eastern Ohio)

Location and Land

As of December 31, 2011, we had acquired leasehold interests in approximately 98,000 gross (49,000 net) acres in the Utica Shale in Eastern Ohio. As of February 20, 2012, we had closed on additional acquisitions bringing our leasehold interests to approximately 107,000 gross (53,500 net) acres. We intend to continue to pursue opportunities in this area and have commitments with various future closing dates that could increase our acreage position in the Utica Shale to an aggregate of approximately 125,000 gross (62,500 net) leasehold acres. We recently spud our first well on our Utica Shale acreage.

Area History

Based on the estimates published by the Ohio Department of Natural Resources, the Utica Shale has a recoverable potential of 1.3 billion to 5.5 billion barrels of oil and 3.8 to 15.7 trillion cubic feet of natural gas. During 2011, a number of oil and gas companies made significant investments in acquiring Utica Shale acreage in Eastern Ohio and applied for drilling permits with the Ohio Department of Natural Resources.

During 2011, most of the drilling activity in the Utica Shale occurred in Eastern Ohio, where our acreage is located. Based on the initial drilling results, the Utica Shale is prospective for oil and natural gas liquids. Specifically, early wells drilled in the Utica Shale indicated potential for production of significant amounts of natural gas liquids, which generally have a higher value, on an energy-equivalent basis, than natural gas.

Geology

The Utica Shale is located in the Appalachian Basin of the United States and Canada. The Utica Shale is a rock unit comprised of organic-rich calcareous black shale that was deposited about 440 million to 460 million years ago during the Late Ordovician period. It overlies the Trenton Limestone and is located a few thousand feet below the Marcellus Shale, which is estimated to be the largest exploration play in the Eastern United States.

Recently, the application of horizontal drilling, combined with multistaged hydraulic fracturing to create permeable flow paths from wellbores into shale units, has resulted in increased drilling activity and production in the Devonian-age Marcellus Shale in the Appalachian Basin states of Pennsylvania, West Virginia, Southern New York and Eastern Ohio. This proven technology has potential for application in other shale units, such as the Ordovician-age Utica Shale, which extends across much of the Appalachian Basin region.

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The Utica Shale is estimated to be thicker and more geographically extensive than the Marcellus Shale and, based on early drilling results, has the potential to support commercial production. The potential source rock portion of the Utica Shale underlies portions of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, West Virginia and Virginia in the United States and is also present beneath parts of Lake Ontario, Lake Erie and part of Ontario, Canada. Throughout the potential source rock area, the Utica Shale ranges in thickness from less than 100 feet to over 500 feet. Over the rock unit as a whole, there is a general thinning from east to west.

The Utica Shale is also significantly deeper than the Marcellus Shale. In some parts of Pennsylvania, the Utica Shale is estimated to be over two miles below sea level and up to 7,000 feet below the Marcellus Shale. However, the depth of the Utica Shale decreases to the west into Ohio and to the northwest under the Great Lakes and into Canada to less than 2,000 feet below sea level.

The Utica Shale is estimated to have higher carbonate and lower clay mineral content than the Marcellus Shale. The difference in mineralogy generally produces a different response to hydraulic fracturing treatments. Based on early fracturing results in the Utica Shale, the hydraulic fracturing methods used in the Marcellus Shale are less productive when applied in the Utica Shale. However, drillers have improved the fracturing rates in other gas shales with similar carbonate content. For example, drillers have discovered methods to make the brittle carbonate zones fracture at higher rates than other gas shale rock units in the Eagle Ford Shale in Texas. Drillers are researching methods to make similar fracturing improvements in the Utica Shale.

Facilities

There are typical land oil and gas processing facilities in the Utica Shale. We will be required to build facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and future activities

We recently spud our first well on our Utica Shale acreage and expect to drill approximately 20 gross (ten net) wells during 2012.

Additional Properties

Louisiana. In addition to our interests in the WCBB, East Hackberry and West Hackberry fields, we also own working interests and overriding royalty interest in various fields in Louisiana, Texas and Oklahoma as described in the following table:

Field	State	Parish/County	Acreage Working Interest	Overriding Royalty Interests	Producing Wells	Non-Producing Wells
Deer Island	Louisiana	Terrebonne	3.125%	0%	1	0
Napoleonville	Louisiana	Assumption	0%	2.5%	3	0
Crest	Texas	Ochiltree	2.000%	0%	1	0
Eagle City South	Oklahoma	Dewey	1.040%	0%	1	0

Thailand. During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II, at a cost of $2.4 million. The remaining interests in Tatex II are owned by entities controlled by Wexford. Tatex II, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately two million acres which includes the Phu Horm Field. During the year ended December 31, 2011, we received $870,000 in distributions, reducing our total investment in Tatex II to $1.0 million. Our investment is accounted for on the equity method. Tatex II accounts for its investment in APICO using the cost method. In December 2006, first gas sales were achieved at the Phu Horm field located in

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northeast Thailand. Phu Horm s initial gross production was approximately 60 million cubic feet per day. For 2011, net gas production was approximately 83 MMcf per day and condensate production was 380 barrels per day. Hess Corporation operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTTEP (20% interest) and ExxonMobil (10% interest). Our gross working interest (through Tatex II as a member of APICO) in the Phu Horm field is 0.7%. Due to the fact that our ownership in the Phu Horm field is indirect and Tatex II s investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

During the first quarter of 2008, we purchased a 5% ownership interest in Tatex Thailand III, LLC, or Tatex III, at a cost of $850,000. In December 2009, we purchased an additional approximately 12.9% ownership interest at a cost of approximately $3.4 million bringing our total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. Tatex III owns a concession covering approximately one million acres. In 2009, Tatex III completed a 3-D seismic survey on this concession. During the year ended December 31, 2011, we paid $3.8 million in cash calls, bringing our total investment in Tatex III to $8.3 million. The first well was drilled on our concession in 2010 and was temporarily abandoned pending further scientific evaluation. Drilling of the second well concluded in March 2011. The second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. The well experienced gas shows and carried a flare measuring up to 25 feet throughout drilling below the intermediate casing point of 9,695 feet. During testing, the well produced at rates as high as 16 million cubic feet per day of gas for short intervals, but would subsequently fall to a sustained rate of 2 million cubic feet per day. Pressure buildup information confirmed that this wellbore lacked the permeability to deliver commercial quantities of gas. Despite an apparently well-developed porosity system suggesting potential for a large amount of gas in place, testing of the well did not exhibit that there was sufficient permeability to produce in commercial quantities. Tatex III intends to continue testing some of the structures identified through its 3-D seismic survey and has begun the application process for two more drilling locations. Tatex III currently expects to drill the first, located to the south of the TEW-E well, late this year or early 2013.

Grizzly Oil Sands. During the third quarter of 2006, we, through our wholly-owned subsidiary Grizzly Holdings Inc., purchased a 24.9% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford. As of December 31, 2011, Grizzly had approximately 754,000 acres under lease in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. Our total net investment in Grizzly was approximately $69.0 million as of December 31, 2011. As of December 31, 2011, Grizzly had drilled an aggregate of 203 core holes and four water supply test wells, tested nine separate lease blocks and conducted a seismic program. In March 2010, Grizzly filed an application for the development of an 11,300 barrel per day oil sand project at Algar Lake. In November 2011, the Government of Alberta provided a formal Order-in Council authorizing the Alberta Energy Resources Conservation Board (ERCB) to issue the formal regulatory approval of Grizzly s Algar Lake SAGD project. Grizzly s currently contemplated 2012 activities include the completion of the 2011/2012 core hole drilling and seismic program, submission of a SAGD project regulatory application for Thickwood Hills and the development of its Algar Lake SAGD project, which includes the fabrication and onsite construction of a central processing facility and the drilling of ten initial SAGD well pairs.

Competition and Markets

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the demand for oil and natural gas and the level of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of

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skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production from WCBB is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt s trade month average P+ value, plus or minus the Platt s HLS/WTI trade month average differential less $2.70 per barrel for transportation. During 2011, we sold 93% and 7% of our oil production to Shell and Windsor, the operator of our Permian wells, respectively, and 22%, 27% and 50% of our natural gas production to Windsor, Chevron and Hilcorp Energy Company, respectively. During 2010, we sold 75% and 19% of our oil production to Shell and Windsor, the operator of our Permian wells, respectively, and 50%, 32%, and 10% of our natural gas production to Windsor, Chevron and Hilcorp Energy Company, respectively. During 2009, we sold 92% and 7% of our oil production to Shell and Windsor, the operator of our Permian wells, respectively, and 45%, 38%, and 16% of our natural gas production to Windsor, Chevron and Hilcorp Energy Company, respectively. We may not continue to have ready access to suitable markets for our future oil and natural gas production.

Oil and natural gas prices can be extremely volatile and are subject to substantial seasonal, political and other fluctuations. The price at which the oil and natural gas we produce may be sold is uncertain and it is possible that under some market conditions the production and sale of oil and natural gas from some or all of our properties may not be economical. Because of all of the factors influencing the price of oil and natural gas, it is impossible to accurately predict future prices.

To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through December 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from January 2013 through June 2013, we entered into fixed price swaps for 1,000 barrels of oil per day at a weighted average price of $113.20 per barrel. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contracts, we delivered approximately 31% of our 2011 production. Under the 2012 contracts, we have committed to deliver approximately 32% to 35% of our estimated 2012 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contacts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, *Derivatives and Hedging,* and related pronouncements.

Regulation

Regulation of Gas and Oil Production

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability.

We own interests in a number of producing oil and natural gas properties located along the Louisiana Gulf Coast, West Texas and the Niobrara Formation in northwestern Colorado. The states in which our fields are located in regulate the production and sale of oil and natural gas, including requirements for obtaining drilling

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permits, the method of developing new fields and the spacing and operation of wells. In addition, regulations governing conservation matters aimed at preventing the waste of oil and natural gas resources could affect the rate of production and may include maximum daily production allowables for wells on a market demand or conservation basis.

Environmental Regulation

Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, or EPA, issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Waste Handling. The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute solid wastes that are subject to the less stringent requirements of non-hazardous waste provisions. However, there can be no assurance that the EPA or the state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as hazardous wastes. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to- date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe that the current costs of managing our wastes as they are presently classified to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or the Superfund law, and analogous state laws, generally imposes strict and joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed responsible parties may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such hazardous substances have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act , the Safe Drinking Water Act or SDWA, the Oil Pollution Act, or OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. Spill prevention, control and countermeasure, or SPCC, plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The OPA,is the primary federal law for oil spill liability. OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The Federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. Some of our new facilities will be required to obtain permits before work can begin, permits may be required for our facilities operations, and existing facilities may be required to incur capital costs to remain in compliance. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. In particular, on August 23, 2011, the EPA published in the *Federal Register* a proposed rule to establish new air emission controls for oil and natural gas production and natural gas processing operations. The new emission standards seek to reduce volatile organic compound, or VOC, emissions, including a 95 percent reduction in VOCs emitted during the construction or modification of hydraulically-fractured wells. The EPA received public comment and conducted public hearing regarding the proposed rules and must take final action on them by April 3, 2012. These laws and regulations may increase the costs of compliance for some

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facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects. Our operations may also soon be affected by rapidly emerging regulation of green house gases, such as carbon dioxide and methane, which are emitted in the course of oil and natural gas exploration and production.

Operational Hazards and Insurance

The oil business involves a variety of operating risks, including the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties for operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of certain wells, oil pollution, third party liability, workers compensation and employers liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery. Additionally, our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these events could cause a significant disruption to our business. For example, we experienced production interruptions in 2005 and 2006 from Hurricanes Katrina and Rita and, in 2008, from Hurricanes Gustav and Ike. A loss not fully covered by insurance could have a material adverse affect on our financial position, results of operations and cash flows.

Currently, we have general liability insurance coverage with an annual aggregate limit of up to $21.0 million which includes environmental impairment coverage for the effects of onshore and offshore pollution on third parties arising from our operations. For our offshore West Cote Blanche Bay properties, we also have a $25.0 million property physical damage policy which insures against most operational perils, such as explosions, fire, vandalism, theft, hail and windstorms, provided, however, that this policy is limited to $10.0 million for damages arising as a result of a named windstorm. In the event of a loss under this policy, we have up to $6.6 million of business interruption coverage available after a 90 day waiting period. All of our insurance coverage includes deductibles of up to $1,000,000 per occurrence ($1.5 million in the case of a named windstorm) that must be met prior to recovery. Additionally, our insurance is subject to customary exclusions and limitations. We reevaluate the purchase of insurance, policy terms and limits annually each May. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

At the depths and in the areas in which we operate, and in light of the vertical and directional drilling that we undertake, we typically do not encounter high pressures or extreme drilling conditions. Accordingly, we typically do not carry a control of well policy, although we currently have such coverage in place for five specific Southern Louisiana wells. In addition, it is currently anticipated that we will carry control of well coverage for all of our Utica Shale wells. We also require all of our third party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider s employees as well as contractors and subcontractors hired by the service provider.

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We have prepared and have in place spill prevention control and countermeasure plans for each of our principal facilities at WCBB in response to federal and state requirements. The plans are reviewed annually and updated as necessary. As required by applicable regulations, our facilities are built with oil containment features and we own certain oil containment equipment, such as oil boom to surround drill sites and production facilities if needed. In addition, we have a national emergency response company on retainer. This company specializes in the clean up of hydrocarbons as a result of spills, blow-outs and natural disasters. This emergency response company has been involved in the clean up efforts of some of the largest oil spills along the Gulf Coast and is on call to us 24 hours a day when its services are needed. It has previously reported that it owns over 164 response vehicles, 65 response vessels, 116 response trailers equipped with decontaminant supplies, personal protective equipment and other equipment used in responding to oil spills, two storage barge sets, allowing for storage of up to 248 barrels of recovered oil each, and over 20 roll-off boxes and vacuum boxes. We pay this company a retainer plus additional amounts when it provides us with clean up services. Our aggregate payments for the retainer and clean up services during 2011 were approximately $220,000. While this company has been able to meet our service needs when required from time to time in the past, it is possible that its ability to provide services to us in the future, if and when needed, could be hindered or delayed in the event of a widespread disaster. However, in light of the depths and the areas in which we operate, and the necessity for gas lift to produce our WCBB wells due to low reservoir pressure at our WCBB field, we believe other companies would be available to us in the event our primary remediation company was unable to perform.

Headquarters and Other Facilities

We own an approximately 28,500 square foot office building in Oklahoma City, Oklahoma that serves as our corporate headquarters. We lease a portion of this office space to certain of our affiliates. We also own an approximately 12,500 square foot building in Lafayette, Louisiana. This building contains approximately 6,200 square feet of finished office area and 6,300 square feet of clear span warehouse area. We also lease 3,722 square feet in a building in Lafayette that we use as our Louisiana headquarters. Each of these properties is suitable and adequate for its use.

Employees

At December 31, 2011, we had 50 employees. An unrelated Louisiana well servicing company provides all necessary field personnel needed to operate the WCBB and the Hackberry fields. In addition, in the past, certain of our employees performed management and administrative services for affiliated companies. We were reimbursed by these affiliates for the salaries and benefits of these individuals based on the estimated time they spent working for those affiliates. For the year ended December 31, 2009, expenses reimbursed to us under these arrangements were $0.6 million, respectively, and are reflected as a reduction in our general and administrative expenses. No amounts were reimbursed to us under these arrangements in 2011 or 2010.

Available Information

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.gulfportenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the Securities and Exchange Commission, or SEC. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

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ITEM 1A. RISK FACTORS
Risks Related to our Business and Industry

The volatility of oil and natural gas prices due to factors beyond our control greatly affects our profitability.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- the level of prices, and expectations about future prices, of oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected rates of declining current production;
- weather conditions, including hurricanes, and other natural disasters that can affect oil and natural gas operations over a wide area;
- the level of consumer demand;
- the price and availability of alternative fuels;
- technical advances affecting energy consumption;
- risks associated with operating drilling rigs;
- the availability of pipeline capacity;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

- speculative trading in crude oil and natural gas derivative contracts;
- political instability or armed conflict in oil and natural gas producing regions; and
- the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On February 15, 2012, the West Texas Intermediate posted price for crude oil was $101.80 per bbl and the Henry Hub spot market price of natural gas was $2.43 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, the availability and cost of credit, the United States mortgage market and a declining real estate market in the United States have contributed

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to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad continues to deteriorate, demand for petroleum products could continue to diminish, which could impact the price at which we can sell our oil, natural gas and natural gas liquids, affect our vendors, suppliers and customers ability to continue operations, and ultimately adversely impact our results of operations, liquidity and financial condition.

Our success depends on finding, developing or acquiring additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made and expect to make in the future substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. Historically, we have financed capital expenditures primarily with cash flow from operations, the issuance of equity securities and borrowings under our bank and other credit facilities. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

We may not have sufficient resources to undertake our exploration, development and production activities or the acquisition of oil and natural gas reserves, our exploratory projects or other replacement activities may not result in significant additional reserves and we may not have success drilling productive wells at low finding and development costs. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

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Our Canadian oil sands project is a complex undertaking and may not be completed at our estimated cost or at all.

During the third quarter of 2006, we, through our wholly-owned subsidiary Grizzly Holdings Inc., purchased a 24.9% interest in Grizzly. The remaining interests in Grizzly are owned by entities controlled by Wexford. As of December 31, 2011, Grizzly had approximately 754,000 acres under lease in the Athabasca region located in the Alberta Province near Fort McMurray within a few miles of other existing oil sands projects. Our total net investment in Grizzly was approximately $69.0 million as of December 31, 2011. As of December 31, 2011, Grizzly had drilled an aggregate of 203 core holes and four water supply test wells, tested nine separate lease blocks and conducted a seismic program. In March 2010, Grizzly filed an application for the development of an 11,300 barrel per day oil sand project at Algar Lake. In November 2011, the Government of Alberta provided a formal Order-in Council authorizing the Alberta Energy Resources Conservation Board (ERCB) to issue the formal regulatory approval of Grizzly s Algar Lake SAGD project. Fabrication and onsite construction on the first phase of development at Algar Lake is currently underway. This is a complex project and financing has not been secured. There can be no assurance that financing can be obtained on commercially reasonable terms or at all.

Shortage of rigs, equipment, raw materials, supplies or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in the number of active rigs in service. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

We rely on a few key employees whose absence or loss could disrupt our operations resulting in a loss of revenues.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services, particularly the loss of Mike Liddell, our Chairman of the Board, James D. Palm, our Chief Executive Officer, Michael G. Moore, our Chief Financial Officer, or our two geophysicists could disrupt our operations resulting in a loss of revenues. We do not have an employment contract with any of our executives, with the exception of Mr. Liddell s written employment agreement and Mr. Palm s oral employment agreement, and our executives are not restricted from competing with us if they cease to be employed by us. Additionally, as a practical matter, any employment agreement we may enter into will not assure the retention of our employees. In addition, we do not maintain key person life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

We may be limited in our ability to book additional proved undeveloped reserves under the recent SEC rules.

One of the impacts of the recent SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Estimates of oil and natural gas reserves are uncertain and may vary substantially from actual production.

There are numerous uncertainties associated with estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures. The reserve information herein represents estimates

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prepared by Netherland, Sewell & Associates, Inc., or NSAI, with respect to our WCBB, Hackberry and Niobrara fields at December 31, 2011, with respect to our WCBB and Niobrara fields at December 31, 2010, and with respect to our WCBB field at December 31, 2009; by Ryder Scott Company L.P., or Ryder Scott, at December 31, 2011, and by Pinnacle Energy Services, LLC, or Pinnacle, at December 31, 2010 and 2009, with respect to our assets in the Permian Basin in West Texas; and by our personnel with respect to our overriding royalty and non-operated interests at December 31, 2011 and with respect to our Hackberry fields, overriding royalty and non-operated interests at December 31, 2010 and 2009. Petroleum engineering is not an exact science. Information relating to our proved oil and natural gas reserves is based upon engineering estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, capital expenditures and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Estimates of reserves as of year-end 2011, 2010 and 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2011, 2010 and 2009, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

The present value of future net revenues from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net revenue from our proved reserves for 2011, 2010 and 2009 on average price equal to the unweighted average of prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2011, 2010 and 2009, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. However, actual future net revenues from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of costs in connection with the development and production of oil and natural gas properties will affect the timing of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

As of December 31, 2011, approximately 56% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and may require successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but these assumptions may not be accurate, and this may not occur.

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There are numerous uncertainties in estimating quantities of bitumen reserves and resources in connection with our equity investment in Grizzly and the indicated level of reserves or recovery of bitumen may not be realized.

There are numerous uncertainties in estimating quantities of bitumen reserves and resources, and the indicated level of reserves or recovery of bitumen may not be realized. In general, estimates of economically recoverable bitumen reserves and the future net cash flow from such reserves are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history may result in variations in the estimated reserves. Reserve and resource estimates may require revision based on actual production experience. Reserve and resources estimates are determined with reference to assumed oil prices and operating costs. Market price fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. The actual gravity or quality of bitumen to be produced from Grizzly s lands cannot be determined at this time.

The marketability of our production is dependent upon compressors, gathering lines, transportation barges and other facilities, certain of which we do not control. When these facilities are unavailable, our operations can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of natural gas lines and transportation barges owned by third parties. In general, we do not control these transportation facilities and our access to them may be limited or denied. A significant disruption in the availability of these transportation facilities or our compression and other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. We are at particular risk with respect to oil and natural gas produced at our WCBB field, which is our largest producing field. In October 2006, for example, a natural gas line in this field operated by our natural gas purchaser was ruptured by a third party contractor, requiring the field to be shut in for approximately seven weeks until the line could be repaired. Further, we are dependent on our oil purchaser to provide the barges necessary to transport our oil production from the WCBB field. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter compression or other production related difficulties, we will be required to again shut in or curtail production from the field. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from the field, would adversely affect our financial condition and results of operations.

A substantial portion of our producing properties is located in Louisiana, making us vulnerable to risks associated with operating in this region.

Our largest field by production, WCBB, is located approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from this region caused by weather conditions such as fog or rain, hurricanes or other natural disasters or lack of field infrastructure. Losses could occur for uninsured risks or in amounts in excess of any existing insurance coverage. We may not be able to obtain and maintain adequate insurance at rates we consider reasonable or that any particular types of coverage will be available.

Our identified drilling locations, which are part of our anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified over 600 drilling locations on our Louisiana, West Texas and Western Colorado properties. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, oil and natural gas prices, inclement weather, costs, drilling results and regulatory changes. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses, and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations and repairs to resume operations

In accordance with what we believe to be customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. In addition, we understand that insurance carriers are modifying or otherwise restricting insurance coverage or ceasing to provide certain types of insurance coverage in the Gulf Coast region. We may not be able to secure additional insurance of bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We acquire significant amounts of unproved property in order to further our development efforts. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, there can be no assurance that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and expected future market prices for oil and natural gas, expected

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costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. Drilling results in our newer oil and liquids-rich shale plays may be more uncertain than in shale plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in newly developed shale formations.

We are not the operator of all of our oil and natural gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

Approximately 67% of our proved reserves at December 31, 2011 are attributable to our acreage position in the Permian Basin. We are not the operator of these properties and may have limited ability to exercise influence over the operations of these and our other non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs, could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator s expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or natural gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

Our undeveloped acreage in our Niobrara Formation must be drilled before lease expiration this year and within the next three years in order to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2011, we had leases in our Niobara Formation representing approximately 13,000 net acres, 32%, 35%, 12%, 1% and 20% of which were scheduled to expire in 2012, 2013, 2014, 2015 and thereafter, respectively. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

We may be unable to identify liabilities associated with the properties that we acquire or obtain protection from sellers against them.

Acquiring oil and gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due

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diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our operations are subject to various governmental regulations which require compliance that can be burdensome and expensive.

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations and injunctions limiting or prohibiting some or all of our operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. The EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as Class II UIC wells. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, both the EPA and the House committee have requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

In March 2011, companion bills entitled the Fracturing Responsibility and Awareness of Chemicals (FRAC) Act of 2009 were reintroduced in the United States Senate and House of Representatives. These bills, which are currently under consideration by Congress, would repeal the exemption for hydraulic fracturing from the SDWA, which would have the effect of allowing the EPA to promulgate regulations requiring permits and implementing potential new requirements on hydraulic fracturing under the SDWA. This could, in turn, require state regulatory agencies in states with programs delegated under the SDWA to impose additional requirements on hydraulic fracturing operations. In addition, the bills would require persons using hydraulic fracturing, such as us, to disclose the chemical constituents, but not the proprietary formulas, of their fracturing fluids to a regulatory

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agency, which would make the information public via the internet. Additionally, fracturing companies would be required to disclose specific chemical contents of fluids, including proprietary chemical formulas, to state authorities or to a requesting physician or nurse if deemed necessary by the physician or nurse in connection with a medical emergency.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In addition, the U.S. Department of Energy is conducting an investigation of practices the EPA could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior has announced that it will consider regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid constituents. Also, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. On August 11, 2011, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board released a report proposing recommendations to reduce the potential environmental impacts from shale gas production.

In addition, on October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges produced by natural gas extraction from underground coalbed and shale formations. The EPA stated that it will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for coalbed methane in 2013 and a proposed rule for shale gas in 2014.

These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities.

Some states in which we operate or hold oil and natural gas interests have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, in September 2011, the Ohio legislature began consideration of legislation that would impose a temporary moratorium on drilling involving hydraulic fracturing pending the delivery of the EPA study regarding the relationship between hydraulic fracturing and drinking water resources. On May 31, 2011, the Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. It was signed into law on June 17, 2011, effective as of September 1, 2011. The Texas Railroad Commission will adopt rules and regulations implementing this legislation in two phases by July 1, 2012 and 2013, respectively. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of federal OSHA for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Effective August 26, 2011, Montana adopted hydraulic fracturing disclosure regulations under which well operators must provide information in drilling permit applications on the estimated volume and types of materials to be used in the proposed hydraulic fracturing activities. Upon completion of the well, well operators must provide the Montana Board of Oil and Gas Conservation with the volume and type of chemicals used, including the additive type, chemical ingredient names, and Chemical Abstracts Number, subject to certain trade secret protections. In September 2011, the North Dakota Industrial Commission proposed new regulations for hydraulic fracturing activities that could require well operators, under certain circumstances, to disclose the hydraulic fluid

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composition, including the trade name, supplier, ingredients, Chemical Abstracts Number, and the maximum ingredient concentrations of all additives in the hydraulic fracturing fluid. We plan to use hydraulic fracturing extensively in connection with the development and production of certain of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing or offshore drilling, including legislation and regulation in the states in which we operate, could reduce the volumes of oil and gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to use of fracturing fluids, impacts on drinking water supplies, use of waters and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing, such as the FRAC Act, are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

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

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The U.S. Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the new legislation, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our derivative contracts in existence at that time, and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation and regulations, our results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the

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volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

The U.S. President s Fiscal Year 2012 Budget Proposal includes provisions that would, if enacted, make significant changes to U.S. tax laws. These changes include, but are not limited to, (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development and (iii) implementing certain international tax reforms. These proposed changes in the U.S. tax laws, if adopted, could adversely affect our business, financial condition, results of operations and cash flows.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Many nations have agreed to limit emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are greenhouse gases, or GHGs, regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol at this time, several states or geographic regions have adopted legislation and regulations to reduce emissions of greenhouse gases. Additionally, on April 2, 2007, the U.S. Supreme Court ruled, in Massachusetts, et al. v. EPA, that the EPA has the authority to regulate carbon dioxide emissions from automobiles as air pollutant under the federal Clean Air Act. Thereafter, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth s atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Subsequently, the EPA adopted two sets of related rules, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective January 2011, although it does not require immediate reductions in GHG emissions. The EPA adopted the stationary source rule in May 2010, and it also became effective January 2011, although it remains subject of several pending lawsuits filed by industry groups. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. More recently, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage, and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011.

Furthermore, in July 2011, the EPA proposed several new emissions standards to reduce volatile organic compound, or VOC, emissions from several types of processes and equipment used in the oil and natural gas industry, including a 95 percent reduction in VOCs emitted during the construction or modification of hydraulically-fractured wells. Additionally, on August 23, 2011, the EPA published a proposed rule in the Federal Register that would establish new air emission controls for oil and natural gas production and natural gas processing operations. The EPA received public comment an conducted public hearings regarding the proposed rules and must take final action on them by April 3, 2012.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security (ACES) Act that, among other things, would have established a cap-and-trade system to regulate greenhouse gas

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emissions and would have required an 80% reduction in GHG emissions from sources within the United States between 2012 and 2050. The ACES Act did not pass the Senate, however, and so was not enacted by the 111th Congress. The United States Congress is likely to again consider a climate change bill in the future. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Currently, while we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Any failure by us to comply with applicable environmental laws and regulations may result in governmental authorities taking actions that could adversely impact our operations and financial condition, including the:

- issuance of administrative, civil and criminal penalties;
- denial, suspension or revocation of necessary permits, licenses or other authorizations;
- imposition of injunctive obligations or limitations on our operations;
- requirement for additional pollution controls; and
- required performance of site investigatory, remedial or other corrective actions.

In addition, 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. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

We face extensive competition in our industry.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

We depend upon two customers for the sale of most of our oil and natural gas production.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of

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gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production from WCBB is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt s trade month average P+ value, plus or minus the Platt s HLS/WTI differential less $2.70 per barrel for transportation. During 2011, we sold 93% and 7% of our oil production to Shell and Windsor, respectively and 22%, 27%, and 50% of our natural gas production to Windsor, Chevron and Hilcorp Energy Company, respectively. During 2010, we sold 75% and 19% of our oil production to Shell and Windsor, respectively and 50%, 32%, and 10% of our natural gas production to Windsor, Chevron and Hilcorp Energy Company, respectively. During 2009, we sold 92% and 7% of our oil production to Shell and Windsor, respectively, and 45%, 38%, and 16% of our natural gas production to Windsor, Chevron and Hilcorp Energy Company, respectively. We may not continue to have ready access to suitable markets for our future oil and natural gas production.

Our method of accounting for oil and natural gas properties may result in impairment of asset value.

We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proven oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil.

Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month prices for 2011, 2010 and 2009 and prior to 2009, unescalated year-end prices, adjusted for any contract provisions or financial derivatives, if any, that hedge oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash writedown is required. A ceiling test impairment can give us a significant loss for a particular period. Once incurred, a write down of oil and natural gas properties is not reversible at a later date, even if oil or gas prices increase. If prices of oil, natural gas and natural gas liquids decrease, we may be required to further write down the value of our oil and gas properties. Future non-cash asset impairments could negatively affect our results of operations.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

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We have entered into forward sales contracts and fixed price swaps and may in the future enter into additional contracts for a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.

To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through December 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from January 2013 through June 2013, we entered into fixed price swaps for 1,000 barrels of oil per day at a weighted average price of $113.20 per barrel. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contracts, we delivered approximately 31% of our 2011 production. Under the 2012 contracts, we have committed to deliver approximately 32% to 35% of our estimated 2012 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, *Derivatives and Hedging*, and related pronouncements.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Risks Related to Our Common Stock

If our quarterly revenues and operating results fluctuate significantly, the price of our common stock may be volatile.

Our revenues and operating results may in the future vary significantly from quarter to quarter. If our quarterly results fluctuate, it may cause our stock price to be volatile. We believe that a number of factors could cause these fluctuations, including:

- changes in oil and natural gas prices;
- changes in production levels;
- changes in governmental regulations and taxes;

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- geopolitical developments;
- the level of foreign imports of oil and natural gas; and
- conditions in the oil and natural gas industry and the overall economic environment.

Because of the factors listed above, among others, we believe that our quarterly revenues, expenses and operating results may vary significantly in the future and that period-to-period comparisons of our operating results are not necessarily meaningful. You should not rely on the results of one quarter as an indication of our future performance. It is also possible that in some future quarters, our operating results will fall below our expectations or the expectations of market analysts and investors. If we do not meet these expectations, the price of our common stock may decline significantly.

Our largest stockholder controls a significant percentage of our common stock, and its interests may conflict with those of our other stockholders.

As of February 20, 2012, Charles E. Davidson, our largest stockholder, beneficially owned approximately 13.3% of our outstanding common stock. As a result, this stockholder acting alone is able to exercise significant influence over most matters requiring approval by our stockholders, including the election of directors and the approval of significant corporate transactions. Such a concentration of ownership may have the effect of delaying or preventing a change in control of us, including transactions in which stockholders might otherwise receive a premium for their shares over then current market prices.

We do not currently pay dividends on our common stock and do not anticipate doing so in the future.

We have paid no cash dividends on our common stock, and we may not pay cash dividends on our common stock in the future. We intend to retain any earnings to fund our operations. Therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, the terms of our credit agreement prohibit the payment of any dividends to the holders of our common stock.

A change of control could limit our use of net operating losses.

As of December 31, 2011, we had a net operating loss, or NOL, carry forward of approximately $116.8 million for federal income tax purposes. Transfers of our stock in the future could result in an ownership change. In such a case, our ability to use the NOLs generated through the ownership change date could be limited. In general, the amount of NOLs we could use for any tax year after the date of the ownership change would be limited to the value of our stock (as of the ownership change date) multiplied by the long-term tax-exempt rate.

Future sales of our common stock may depress our stock price.

We and certain of our stockholders have registered a substantial number of shares of our common stock under a registration statement filed with the SEC. Sales of these shares of our common stock in the public market or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, sales by certain of our stockholders of their shares could impair our ability to raise capital through the sale of common or preferred stock. As of February 20, 2012, there were 55,621,371 shares of our common stock issued and outstanding, excluding 203,348 shares of unvested restricted stock awarded under our Amended and Restated 2005 Stock Incentive Plan, 29,832 shares issuable upon exercise of outstanding warrants and 356,241 shares issuable upon exercise of outstanding options to purchase our common stock granted under our Amended and Restated 2005 Stock Incentive Plan.

We could issue preferred stock which could be entitled to dividend, liquidation and other special rights and preferences not shared by holders of our common stock or which could have anti-takeover effects.

We are authorized to issue up to 5,000,000 shares of preferred stock, par value $0.01 per share. Shares of preferred stock may be issued from time to time in one or more series as our board of directors, by resolution or

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resolutions, may from time to time determine each such series to be distinctively designated. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions, if any, of each such series of preferred stock may differ from those of any and all other series of preferred stock at any time outstanding, and, subject to certain limitations of our certificate of incorporation and the Delaware General Corporation Law, or DGCL, our board of directors may fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and qualifications, limitations and restrictions thereof, of each such series preferred stock. The issuance of any such preferred stock could materially adversely affect the rights of holders of our common stock and, therefore, could reduce the value of our common stock.

In addition, specific rights granted to future holders of preferred stock could be used to restrict our ability to merge with, or sell our assets to, a third party. The ability of our board of directors to issue preferred stock could discourage, delay or prevent a takeover of us, thereby preserving control of the company by the current stockholders.

The existence of some provisions in our organizational documents could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Proved Oil and Natural Gas Reserves

SEC Rule-Making Activity

In December 2008, the SEC released its final rule for Modernization of Oil and Gas Reporting. These rules require disclosure of oil and gas proved reserves by significant geographic area, using the arithmetic 12-month average beginning-of-the-month price for the year, as opposed to year-end prices as had previously been required unless contractual arrangements designate the price to be used. Other significant amendments included the following:

- Disclosure of unproved reserves: probable and possible reserves may be disclosed separately on a voluntary basis.

- Proved undeveloped reserve guidelines: reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.

- Reserves estimation using new technologies: reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

- Reserves personnel and estimation process: additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.

Non-traditional resources: the definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009, as required by the SEC.

Evaluation and Review of Reserves.

Reserve estimates at December 31, 2011 were prepared by NSAI with respect to our WCBB, Hackberry and Niobrara fields (33% of our proved reserves at December 31, 2011), by Ryder Scott with respect to our assets in

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the Permian Basin in West Texas (67% of our proved reserves at December 31, 2011) and by our personnel with respect to our overriding royalty and non-operated interests (less than 1% of our proved reserves at December 31, 2011).

NSAI and Ryder Scott are independent petroleum engineering firms. Copies of their summary reserve reports are included as Exhibit 99.1 and 99.2, respectively, to this Annual Report on Form 10-K. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with NSAI and Ryder Scott to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our WCBB, Hackberry and Niobrara fields and our assets in the Permian Basin, respectively. Our internal technical team members meet with NSAI and Ryder Scott periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI and Ryder Scott for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our proved reserves attributable to our other minority interests are prepared internally by our internal staff of petroleum engineers and geoscience professionals. Our chief reserve engineer is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with over 30 years of reservoir and operations experience and our geophysical staff has over 60 years combined industry experience. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our experienced reservoir engineers or under their direct supervision;
- review by our reservoir engineering department of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our reservoir engineering department to our Chief Executive Officer; and
- verification of property ownership by our land department.

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The following table sets forth our estimated proved reserves at December 31, 2011, 2010 and 2009:

	Year Ended December 31,					
	2011		2010		2009	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved developed	7,485	6,152	7,230	6,068	6,165	4,325
Proved undeveloped	9,260	9,576	12,474	10,090	11,323	10,007
Total (1)	16,745	15,728	19,704	16,158	17,488	14,332

	Year Ended December 31,		
	2011	2010	2009
Total net proved oil and natural gas reserves (MBOE) (1)	19,367	22,397	19,877
PV-10 value (in millions) (2)	$ 490.5	$ 392.6	$ 263.0
Standardized measure (in millions) (3)	$ 376.7	$ 315.5	$ 240.8

(1) Estimates of reserves as of year-end 2011, 2010 and 2009 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2011, 2010 and 2009, respectively, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2011, 2010 and 2009. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

(2) Represents present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proven reserves. The estimated future net revenues set forth above were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on certain prevailing economic conditions. The estimated future production in our reserve reports for the years ended December 31, 2011, 2010 and 2009 is priced based on the 12-month unweighted arithmetic average of the first-day-of-the month price for the period January through December of the applicable year, using $96.19 per barrel and $4.12 per MMBtu, $76.16 per barrel and $4.38 per MMBtu and $57.90 per barrel and $3.87 per MMBtu, respectively, and in each case adjusted by lease for transportation fees and regional price differentials.

PV-10 is a non-GAAP measure because it excludes income tax effects. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. PV-10 is not a measure of financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of PV-10 to the most directly comparable GAAP measure standardized measure of discounted future net cash flows. The following table reconciles the standardized measure of future net cash flows to the PV-10 value:

	December 31,		
	2011	2010	2009
Standardized measure of discounted future net cash flows	$ 376,681,000	$ 315,487,000	$ 240,774,000
Add: Present value of future income tax discounted at 10%	113,791,000	77,117,000	22,237,000

PV-10 value	$ 490,472,000	$ 392,604,000	$ 263,011,000

(3) The standardized measure represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

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The above table does not include proved reserves net to our interest in Tatex II, Tatex III or Grizzly. For further discussion of our interest in Tatex II, Tatex III and Grizzly, see Item 1. Description of Business Additional Properties.

The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Risk Factors contained elsewhere in this Form 10-K. We have not filed any estimates of total, proved net oil or gas reserves with any federal authority or agency other than the SEC since the beginning of our last fiscal year.

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves, or PUDs, at December 31, 2011, 2010 and 2009 and changes in proved reserves during the last three years are contained in the Supplemental Information on Oil and Gas Exploration and Production Activities, or Supplemental Information, in Note 20 to our consolidated financial statements included in this report. Also contained in the Supplemental Information are our estimates of future net cash flows and discounted future net cash flows from proved reserves. Additional information regarding our proved reserves can be found in Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations and Critical Accounting Policies and Estimates included in this report.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2011, our proved undeveloped reserves totaled 9,260 MBOE of oil and 9,576 MMcf of natural gas, for a total of 10,856 MBOE. Approximately 88% of our PUDs at year-end 2011 were located in the Permian Basin, 6% of our PUDs were located in WCBB, 3% were located in our East Hackberry field and 3% of our PUDs were located in our Niobrara field. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Changes in PUDs that occurred during 2011 were primarily due to:

- Additions of 531 MBOE attributable to 2011 acquisitions and extensions;
- Conversion of approximately 2,502 MBOE attributable to PUDs into proved developed reserves;
- Positive revisions of approximately 331 MBOE in PUDs due to changes in commodity prices; and
- Downward revisions to estimates of approximately 1,660 MBOE

Costs incurred relating to the development of PUDs were approximately $41.2 million in 2011. Estimated future development costs relating to the development of PUDs are projected to be approximately $52.6 million in 2012, $49.9 million in 2013, $55.4 million in 2014, $51.4 million in 2015 and $58.3 in 2016.

All PUD drilling locations are scheduled to be drilled prior to the end of 2016.

As of December 31, 2011, 16% of our total proved reserves were classified as proved developed non-producing.

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Production, Prices, and Production Costs

The following table presents our production volumes, average prices received and average production costs during the periods indicated:

	2011	2010	2009
Production Volumes:			
Oil (MBbls)	2,128	1,777	1,531
Gas (MMcf)	878	788	491
Natural gas liquids (MGal)	2,468	2,821	2,719
Oil equivalents (MBOE)	2,333	1,976	1,677
Average Prices:			
Oil (per Bbl)	$ 104.33(1)	$ 68.29(1)	$ 53.29(1)
Gas (per Mcf)	$ 4.37	$ 4.40	$ 4.06
Natural gas liquids (per Gal)	$ 1.25	$ 1.00	$ 0.73
Oil equivalents (per BOE)	$ 98.13	$ 64.61	$ 51.01
Production Costs:			
Average production costs (per BOE)	$ 8.96	$ 8.92	$ 9.73
Average production taxes (per BOE)	$ 11.29	$ 7.07	$ 5.84
Total production costs and production taxes (per BOE)	$ 20.25	$ 15.99	$ 15.57

(1) Includes various derivative contracts at a weighted average price of:

January	December 2009	$ 55.01
January	December 2010	$ 57.55
January	December 2011	$ 86.96

Excluding the effect of fixed price swap contracts, the average oil price for 2011 would have been $107.13 per barrel of oil and $100.68 per BOE. The total volume hedged for 2011 represented approximately 31% of our total sales volumes for the year. Excluding the effect of forward sales contracts, the average oil price for 2010 would have been $78.12 per barrel of oil and $73.45 per BOE. The total volume hedged for 2010 represented approximately 45% of our total sales volumes for the year. Excluding the effect of forward sales contracts, the average oil price for 2009 would have been $57.98 per barrel of oil and $55.29 per BOE. The total volume hedged for 2009 represented approximately 49% of our total sales volumes for the year.

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The following table provides a summary of our production, average sales prices and average production costs for oil and gas fields containing 15% or more of our total proved reserves as of December 31, 2011:

	Year Ended December 31,		
	2011	2010	2009
WCBB			
Net Production			
Oil (MBbls)	1,258	1,176	1,209
Gas (MMcf)	237	410	192
NGL (Mgal)			
Total (MBOE)	1,298	1,244	1,241
Average Sales Price:			
Oil (per Bbl)	$ 104.49	$ 62.57	$ 52.39
Gas (per Mcf)	$ 4.16	$ 4.44	$ 4.44
NGL (per Gal)	$	$	$
Average Production Cost (per BOE)	$ 8.71	$ 8.90	$ 8.54
Permian Basin			
Net Production			
Oil (MBbls)	208	134	118
Gas (MMcf)	272	256	236
NGL (Mgal)	2,436	2,797	2,694
Total (MBOE)	312	243	221
Average Sales Price:			
Oil (per Bbl)	$ 90.86	$ 76.48	$ 55.19
Gas (per Mcf)	$ 3.94	$ 4.21	$ 3.72
NGL (per Gal)	$ 1.25	$ 1.00	$ 0.73
Average Production Cost (per BOE)	$ 17.59	$ 9.78	$ 10.71

Productive Wells and Acreage

The following table presents our total gross and net productive and non-productive wells, expressed separately for oil and gas, and the total gross and net developed and undeveloped acres as of December 31, 2011.

Field	NRI/WI (1) Percentages	Productive Oil Wells (2)		Productive Gas Wells		Non-Productive Oil Wells		Non-Productive Gas Wells		Developed Acreage (3)		Undeveloped Acreage (4)	
		Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
West Cote Blanche Bay Field (5)	80.1/100	94	94	1	1	171	171	18	18	5,668	5,668		
E. Hackberry Field (6)	79.4/100	30	30			93	93			3,291	3,291		
W. Hackberry Field	87.5/100	2	2			23	23			592	592		
Permian Basin	35.4/46.87	121	57							8,880	4,119	26,786	11,190
Niobrara Formation (7)	39.7/47.9	6	3			2	1			3,954	1,977	26,033	13,016
Williston Basin (8)	2.8/3.3	6	.2							1,708	132	3,659	685
Overrides/Royalty Non-operated	Various	133	.2										
Total		392	186.4	1	1	289	288	18	18	24,093	15,779	56,478	24,891

(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes six gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 36% of our acreage is developed acreage and has been perpetuated by production.

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(4) E. Hackberry acreage does not include 2,868 net acres subject to a two-year exploration agreement.
(5) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(6) NRI shown is for producing wells.
(7) The leases relating to our Niobrara Formation acreage will expire at the end of their respective primary terms unless the applicable leases are renewed or extended, we have commenced the necessary operations required by the terms of the applicable leases or we have obtained actual production from acreage subject to the applicable leases, in which event they will remain in effect until the cessation of production. Leases representing 32%, 35%, 12%, 1% and 20% of our total Niobrara undeveloped acreage are currently scheduled to expire in 2012, 2013, 2014, 2015 and thereafter, respectively.
(8) NRI/WI is from wells that have been drilled or in which we have elected to participate.

Completed and Present Drilling and Recompletion Activities

The following table sets forth information with respect to wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	2011		2010		2009	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Recompletions:						
Productive	100	96	87	84	64	62.5
Dry						
Total	100	96	87	84	64	62.5
Development:						
Productive	82	57	57	42	25	18
Dry	3	3			1	1
Total	85	60	57	42	26	19
Exploratory:						
Productive	1	1			1	1
Dry						
Total	1	1			1	1

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a cursory review of title to undeveloped oil and natural gas leases at the time they are acquired and to obtain more extensive title examinations when acquiring producing properties. In future acquisitions, we will conduct title examinations on material portions of such properties in a manner generally consistent with industry practice. Certain of our oil and natural gas properties may be subject to title defects, encumbrances, easements, servitudes or other restrictions, none of which, in management s opinion, will in the aggregate materially restrict our operations.

ITEM 3. LEGAL PROCEEDINGS

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the

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severance taxes we would have had to pay had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against our company seeking $2,275,729 in severance taxes, plus interest and court costs. We filed a response denying any liability to the LDR for underpayment of severance taxes and are defending our company in the lawsuit. The LDR had taken no further action on this lawsuit since filing its petition two years ago until recently when it propounded discovery requests to which we have responded. We recently served discovery requests on the LDR and are awaiting the LDR s response.

In December 2010, the LDR filed two identical lawsuits against us in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney s fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the first lawsuit filed by the LDR in 2009, we have denied all liability and will vigorously defend the lawsuit. The cases are in the very early stages, and we have not yet filed a response to these lawsuits. Recently, the LDR filed motions to stay the lawsuits before we filed any responsive pleadings. The LDR has advised us that it intends to pursue settlement discussions with us and other similarly situated defendants in separate proceedings.

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us, Great White Pressure Control LLC, or Great White, and six former Cudd employees in the 129th Judicial District Harris County, Texas. The lawsuit was subsequently removed to the United States District Court for the Southern District of Texas (Houston Division). The lawsuit alleged RICO violations and several other causes of action relating to Great White s employment of the former Cudd employees and sought unspecified monetary damages and injunctive relief. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. We filed a motion for summary judgment on October 5, 2007. The Court entered a final interlocutory judgment in favor of all defendants, including us, on April 8, 2008. On November 3, 2008, Cudd filed its appeal with the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit vacated the district court decision finding, among other things, that the district court should not have entered summary judgment without first allowing more discovery. The case was remanded to the district court, and Cudd filed a motion to remand the case to the original state court, which motion was granted. On February 3, 2010, Cudd filed its second amended petition with the state court (a) alleging that we conspired with the other defendants to misappropriate, and misappropriated Cudd s trade secrets and caused its employees to breach their fiduciary duties, and (b) seeking unspecified monetary damages. On April 13, 2010, our motion to be dismissed from the proceeding for lack of personal jurisdiction was denied. This state court proceeding is in its initial stages. In 2011, the parties have continued with written discovery and production of documents. On February 15, 2011, Cudd filed a third amended petition seeking $26.5 million (based on a report prepared by its expert) plus disgorgement of $6.0 million in payments by Great White to the individual defendants and punitive damages. Gulfport denies these claims with respect to itself. Recently, the parties began the process of scheduling and taking depositions and it is anticipated that the case will remain in the discovery phase for at least the next several months.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for contamination across the surface of where the defendants operated in an action entitled Reeds et al. v. BP American Production Company et al., 38th Judicial District. No. 10-18714. The plaintiffs original petition for damages, which did not name us as a defendant, alleges that the plaintiffs property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. Plaintiffs allege that the defendants conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and

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response costs and stigma damages. On December 7, 2010, we were served with a copy of the plaintiffs first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including us, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses; and damages for evaluation and remediation of any contamination that threatens groundwater. In addition to us, current defendants include ExxonMobil Oil Corporation, Mobil Exploration & Producing North America Inc., Chevron U.S.A. Inc., The Superior Oil Company, Union Oil Company of California, BP America Production Company, Tempest Oil Company, Inc., ConocoPhillips Company, Continental Oil Company, WM. T. Burton Industries, Inc., Freeport Sulphur Company, Eagle Petroleum Company, U.S. Oil of Louisiana, M&S Oil Company, and Empire Land Corporation, Inc. of Delaware. On January 21, 2011, we filed a pleading challenging the legal sufficiency of the petitions on several grounds and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. In response to the pleadings filed by us and similar pleadings filed by other defendants, the plaintiffs filed a third amending petition with exhibits which expands the description of the property at issue, attaches numerous aerial photos and identifies the mineral leases at issue. In response, we and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. Some of the defendants grounds for challenging the plaintiffs petitions were heard by the court on May 25, 2011 and were denied. The court signed the written judgment on December 9, 2011. We noticed our intent to seek supervisory review on December 19, 2011 and the trial court fixed a return date of January 11, 2012 for the filing of the writ application. We filed our supervisory writ and the matter is currently pending before the Louisiana Third Circuit Court of Appeal. We have served discovery requests and are currently responding to discovery requests from the plaintiffs.

Due to the current stages of the above litigation, the outcomes are uncertain and management cannot determine the amount of loss, if any, that may result. Litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse affect on our financial condition or results of operations.

In addition to the above, we have been named as a defendant in various other lawsuits related to our business. The ultimate resolution of such other matters is not expected to have a material adverse effect on our financial condition or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Since July 14, 2006, our common stock has been quoted on The NASDAQ Global Select Market under the symbol GPOR. The following table sets forth the high and low sale prices of our common stock for the periods presented:

	Price Range of Common Stock	
	High	Low
2010		
First Quarter	$ 12.68	$ 8.89
Second Quarter	15.25	10.60
Third Quarter	14.71	10.37
Fourth Quarter	22.92	13.59
2011		
First Quarter	$ 36.38	$ 20.00
Second Quarter	38.09	23.84
Third Quarter	37.49	22.00
Fourth Quarter	37.80	18.72
2012		
First Quarter (through February 15, 2012)	$ 36.54	$ 29.63

On February 15, 2012, the last reported sale price of our common stock on The NASDAQ Global Select Market was $35.34.

Unregistered Sales of Equity Securities and Use of Proceeds

None, except that we issued 566 shares of our common stock upon exercise of certain outstanding warrants to purchase our common stock in transactions exempt from registration under the Securities Act of 1933, as amended.

Holders of Record

At the close of business on February 15, 2012, there were 332 stockholders of record holding 55,621,371 shares of our outstanding common stock. There were approximately 21,921 beneficial owners of our common stock as of February 15, 2012.

Dividend Policy

We have never paid dividends on our common stock. We currently intend to retain all earnings to fund our operations. Therefore, we do not intend to pay any cash dividends on the common stock in the foreseeable future. In addition, the terms of our credit facility prohibit the payment of any dividends to the holders of our common stock.

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ITEM 6. SELECTED FINANCIAL DATA

You should read the following selected consolidated financial data in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and the related notes appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2011, December 31, 2010 and December 31, 2009 and the selected consolidated balance sheet data at December 31, 2011 and December 31, 2010 are derived from our audited consolidated financial statements appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2008 and December 31, 2007 and the selected consolidated balance sheet data at December 31, 2009, December 31, 2008 and December 31, 2007 are derived from our audited consolidated financial statements that are not included in this report. The historical data presented below is not indicative of future results. We did not pay any cash dividends on our common stock during any of the periods set forth in the following table.

	Fiscal Year Ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
Selected Consolidated Statements of Operations Data:					
Revenues	$ 229,254,000	$ 127,921,000	$ 85,968,000	$ 141,873,000	$ 106,315,000
Costs and expenses:					
Lease operating expenses	20,897,000	17,614,000	16,316,000	22,856,000	16,670,000
Production taxes	26,333,000	13,966,000	9,797,000	15,813,000	12,667,000
Depreciation, depletion and amortization	62,320,000	38,907,000	29,225,000	42,472,000	29,681,000
Impairment of oil and natural gas properties				272,722,000	
General and administrative	8,074,000	6,063,000	4,992,000	6,843,000	5,802,000
Accretion expense	666,000	617,000	582,000	560,000	554,000
	118,290,000	77,167,000	60,912,000	361,266,000	65,374,000
Income (Loss) from Operations	110,964,000	50,754,000	25,056,000	(219,393,000)	40,941,000
Other (Income) Expense:					
Interest expense	1,400,000	2,761,000	2,309,000	4,762,000	3,091,000
Insurance recoveries			(1,050,000)	(769,000)	
Settlement of fixed price contracts				(39,000,000)	
Interest income	(186,000)	(387,000)	(564,000)	(540,000)	(523,000)
Loss from equity method investments	1,418,000	977,000	706,000	656,000	477,000
	2,632,000	3,351,000	1,401,000	(34,891,000)	3,045,000
Income (Loss) before Income Taxes	108,332,000	47,403,000	23,655,000	(184,502,000)	37,896,000
Income Tax Expense (Benefit)	(90,000)	40,000	28,000		121,000
Net Income (Loss)	108,422,000	47,363,000	23,627,000	(184,502,000)	37,775,000
Net Income (Loss) Available to Common Stockholders	$ 108,422,000	$ 47,363,000	$ 23,627,000	$ (184,502,000)	$ 37,775,000
Net Income (Loss) Per Common Share Basic:	$ 2.22	$ 1.08	$ 0.55	$ (4.33)	$ 1.03
Net Income (Loss) Per Common Share Diluted:	$ 2.20	$ 1.07	$ 0.55	$ (4.33)	$ 1.01

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	At December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
Selected Consolidated Balance Sheet Data:					
Total assets	$ 691,158,000	$ 319,693,000	$ 227,344,000	$ 221,873,000	$ 419,137,000
Total debt, including current maturity	$ 2,283,000	$ 51,917,000	$ 52,428,000	$ 70,731,000	$ 66,533,000
Total liabilities	$ 58,808,000	$ 108,637,000	$ 102,293,000	$ 107,772,000	$ 115,015,000
Stockholders equity	$ 632,350,000	$ 211,056,000	$ 125,051,000	$ 114,101,000	$ 304,122,000

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This discussion contains forward-looking statements reflecting our current expectations, estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled Risk Factors and Cautionary Note Regarding Forward-Looking Statements appearing elsewhere in this Annual Report on Form 10-K.

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields, and in West Texas in the Permian Basin. During 2010, we acquired an acreage position in the Niobrara Formation of northwestern Colorado and, during 2011, we acquired our initial acreage position in the Utica Shale in Eastern Ohio and have commitments to acquire additional acreage there. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, and have interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2011 Highlights

- Oil and natural gas revenues increased 79% to $229.0 million for the year ended December 31, 2011 from $127.6 million for the year ended December 31, 2010.

- Net income increased 129% to $108.4 million for the year ended December 31, 2011 from $47.4 million for the year ended December 31, 2010.

- Production increased 18% to approximately 2,333,208 barrels of oil equivalent, or BOE, for the year ended December 31, 2011 from approximately 1,975,576 BOE for the year ended December 31, 2010.

- During 2011, we drilled 86 gross (61 net) wells, which includes 40 gross (17 net) wells drilled by our operators in the Permian Basin and Bakken, and recompleted 100 gross (96 net) wells. Of our 86 new wells drilled, 75 were completed as producing wells, three were non-productive and eight were waiting on completion.

- During 2011, we acquired approximately 600 additional net acres in the Permian Basin, which brought our total net acreage position in the Permian Basin to approximately 15,300 net acres.

- During 2011, we acquired leasehold interests in approximately 98,000 gross (49,000 net) acres in the Utica Shale in Eastern Ohio. We intend to continue to pursue additional opportunities in this area and have commitments with various future closing dates which could increase our acreage position in the Utica Shale to an aggregate of approximately 125,000 gross (62,500 net) leasehold acres. We recently spud our first well on our Utica Shale acreage in February 2012.

- In March, July and December of 2011, we completed a series of underwritten public offerings of an aggregate of 10,810,000 shares of our common stock and received approximately $307.1 million in aggregate net proceeds, which we used to repay then outstanding balances under our revolving credit facility, fund acquisitions of certain of our Utica Shale properties and for general corporate purposes, which include future capital expenditures associated with drilling, development and infrastructure, principally in the Utica Shale in Ohio.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates including those related to oil and natural gas properties, revenue recognition, income taxes and commitments and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements:

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period 2011, 2010 and 2009, and prior to 2009, unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $138.6 million at December 31, 2011 and $16.8 million at December 31, 2010. These costs are reviewed quarterly by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the period January December of the applicable year beginning with 2009, and prior to 2009, unescalated year-end prices and costs, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272.7 million for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids decline, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations. No ceiling test impairment was required for the year ended December 31, 2011.

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Asset Retirement Obligations. We have obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities.

We account for abandonment and restoration liabilities under FASB ASC 410 which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjustment risk free interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Ryder Scott Company and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2011 on a well-by-well basis for our properties.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows derived from these reserve estimates have been prepared in accordance with SEC guidelines. The accuracy of our reserve estimates is a function of many factors including the following:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. Therefore, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable.

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Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2011, a valuation allowance of $12.3 million had been provided for deferred tax assets based on the uncertainty of future taxable income.

Revenue Recognition. We derive almost all of our revenue from the sale of crude oil and natural gas produced from our oil and gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and actual payment received for all prior months are recorded at the end of the quarter after payment is received. Historically, our actual payments have not significantly deviated from our accruals.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. We are involved in certain litigation for which the outcome is uncertain. Changes in the certainty and the ability to reasonably estimate a loss amount, if any, may result in the recognition and subsequent payment of legal liabilities.

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of FASB ASC 815, *Derivatives and Hedging*, as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and our realized prices, time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings.

To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through December 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from January 2013 through June 2013, we entered into fixed price swaps for 1,000 barrels of oil per day at a weighted average price of $113.20 per barrel. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contracts, we delivered approximately 31% of our 2011 production. Under the 2012 contracts, we have committed to deliver approximately 32% to 35% of our estimated 2012 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

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RESULTS OF OPERATIONS

Results of Operations

The markets for oil and natural gas have historically been, and will continue to be, volatile. Prices for oil and natural gas may fluctuate in response to relatively minor changes in supply and demand, market uncertainty and a variety of factors beyond our control.

The following table presents our production volumes, average prices received and average production costs during the periods indicated:

	2011	2010	2009
Production Volumes:			
Oil (MBbls)	2,128	1,777	1,531
Gas (MMcf)	878	788	491
Natural gas liquids (MGal)	2,468	2,821	2,719
Oil equivalents (MBOE)	2,333	1,976	1,677
Average Prices:			
Oil (per Bbl)	$ 104.33(1)	$ 68.29(1)	$ 53.29(1)
Gas (per Mcf)	$ 4.37	$ 4.40	$ 4.06
Natural gas liquids (per Gal)	$ 1.25	$ 1.00	$ 0.73
Oil equivalents (per BOE)	$ 98.13	$ 64.61	$ 51.01
Production Costs:			
Average production costs (per BOE)	$ 8.96	$ 8.92	$ 9.73
Average production taxes (per BOE)	$ 11.29	$ 7.07	$ 5.84
Total production costs and production taxes (per BOE)	$ 20.25	$ 15.99	$ 15.57

(1) Includes various derivative contracts at a weighted average price of:

January	December 2009	$ 55.01
January	December 2010	$ 57.55
January	December 2011	$ 86.96

Excluding the net effect of fixed price swap contracts, the average oil price for 2011 would have been $107.13 per barrel of oil and $100.68 BOE. The total volume hedged for 2011 represented approximately 31% of our total sales volumes for the year. Excluding the net effect of forward sales contracts, the average oil price for 2010 would have been $78.12 per barrel of oil and $73.45 per BOE. The total volume hedged for 2010 represented approximately 45% of our total sales volumes for the year. Excluding the effect of forward sales contracts, the average oil price for 2009 would have been $57.98 per barrel of oil and $55.29 per BOE. The total volume hedged for 2009 represented approximately 49% of our total sales volumes for the year.

From 2010 to 2011, our net equivalent oil production increased 18% from 1,975,576 BOE to 2,333,208 BOE due to the results of our 2011 drilling and recompletion activities. From 2009 to 2010, our net equivalent oil production also increased 18% from 1,677,000 BOE to 1,976,000 BOE due to increased drilling activity, the success of our drilling activities and our acquisitions of additional properties in the Permian Basin and the Niobrara Formation. We currently estimate that our 2012 production will be between 3,000,000 and 3,200,000 BOE. However, such estimate may change based on a change in our expected drilling and recompletion activities or the changing economic climate and unforeseen events, such as hurricanes.

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Comparison of the Years Ended December 31, 2011 and December 31, 2010

We reported net income of $108,422,000 for the year ended December 31, 2011 as compared to net income of $47,363,000 for the year ended December 31, 2010. This 129% increase in period-to-period net income was due primarily to an 18% increase in net production to 2,333,208 BOE and a 52% increase in realized BOE prices to $98.13 for the year ended December 31, 2011, partially offset by a 19% increase in lease operating expenses, a 33% increase in general and administrative expenses and an 89% increase in production taxes.

Oil and Gas Revenues. For the year ended December 31, 2011, we reported oil and natural gas revenues of $228,953,000 as compared to oil and natural gas revenues of $127,636,000 during 2010. This $101,317,000, or 79%, increase in revenues was primarily attributable to an 18% increase in net production to 2,333,208 BOE from 1,975,576 BOE and a 52% increase in realized BOE prices to $98.13 from $64.61, in each case for the year ended December 31, 2011 as compared to the year ended December 31, 2010.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2011 and December 31, 2010:

	Year Ended December 31,	
	2011	2010
Oil production volumes (MBbls)	2,128	1,777
Gas production volumes (MMcf)	878	788
Natural gas liquids production volumes (MGal)	2,468	2,821
Oil equivalents (MBOE)	2,333	1,976
Average oil price (per Bbl)	$ 104.33	$ 68.29
Average gas price (per Mcf)	$ 4.37	$ 4.40
Average natural gas liquids (per Gal)	$ 1.25	$ 1.00
Oil equivalents (per BOE)	$ 98.13	$ 64.61

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $20,897,000 for the year ended December 31, 2011 from $17,614,000 for 2010. This increase was mainly the result of an increase in expenses related to chemicals and fuel, equipment repairs and maintenance, field supervision, overhead, property taxes, rentals, salt water disposal and well workovers.

Production Taxes. Production taxes increased to $26,333,000 for the year ended December 31, 2011 from $13,966,000 for 2010. This increase was primarily related to an 18% increase in production and a 52% increase in the average realized BOE price received resulting in a 79% increase in oil and gas revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $62,320,000 for the year ended December 31, 2011, and consisted of $61,965,000 in depletion of oil and natural gas properties and $355,000 in depreciation of other property and equipment, as compared to total DD&A expense of $38,907,000 for 2010. This increase was due to an increase in our full cost pool as a result of our capital activities, an increase in our production and a decrease in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $8,074,000 for the year ended December 31, 2011 from $6,063,000 for 2010. This $2,011,000 increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in legal expenses, franchise taxes and bank fees, partially offset by an increase in administrative services reimbursements under the acquisition team agreement and an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $666,000 for the year ended December 31, 2011 from $617,000 for the same period in 2010.

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Interest Expense. Interest expense decreased to $1,400,000 for the year ended December 31, 2011 from $2,761,000 for 2010 due to a decrease in the interest rate paid and the repayment of all of our outstanding debt under our revolving credit facility during the fourth quarter of 2011 so that no amounts were outstanding as of December 31, 2011, as compared to $49,500,000 outstanding as of the same date in 2010. Further, during 2010, in conjunction with the repayment of our prior revolving credit facility on September 30, 2010, we expensed approximately $225,000 in unamortized loan fees associated with this facility, which is included in interest expense in our consolidated statements of operations for the year ended December 31, 2010. Total weighted debt outstanding under our revolving credit facility was $21,084,000 for the year ended December 31, 2011 and $46,931,000 for 2010. As of December 14, 2011 (the latest date during the year ended December 31, 2011 on which we had borrowings outstanding), amounts borrowed under our credit facility bore interest at the Eurodollar rate of 2.26%.

Income Taxes. As of December 31, 2011, we had a net operating loss carry forward of approximately $116.8 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2011, a valuation allowance of $12,347,000 had been provided for deferred tax assets, with the exception of $1,000,000 related to alternative minimum taxes. We recognized an income tax benefit of $90,000 for the year ended December 31, 2011.

Comparison of the Years Ended December 31, 2010 and December 31, 2009

We reported net income of $47,363,000 for the year ended December 31, 2010, as compared to net income of $23,627,000 for the year ended December 31, 2009. This 100% increase in 2010 was due primarily to a 27% increase in realized BOE prices to $64.61 from $51.01 and an 18% increase in net production to 1,976,000 BOE, partially offset by an 8% increase in lease operating expenses, a 21% increase in general and administrative expenses and a 43% increase in production taxes.

Oil and Gas Revenues. For the year ended December 31, 2010, we reported oil and natural gas revenues of $127,636,000 as compared to oil and natural gas revenues of $85,576,000 during 2009. This $42,060,000, or 49%, increase in revenues is primarily attributable to a 27% increase in realized BOE prices to $64.61 from $51.01 and an 18% increase in net production to 1,975,576 BOE for the year ended December 31, 2010 from 1,677,474 BOE for the year ended December 31, 2009.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2010 and December 31, 2009:

	Year Ended December 31,	
	2010	2009
Oil production volumes (MBbls)	1,777	1,531
Gas production volumes (MMcf)	788	491
Natural gas liquids production volumes (MGal)	2,821	2,719
Oil equivalents (MBOE)	1,976	1,677
Average oil price (per Bbl)	$ 68.29	$ 53.29
Average gas price (per Mcf)	$ 4.40	$ 4.06
Average natural gas liquids (per Gal)	$ 1.00	$ 0.73
Oil equivalents (per BOE)	$ 64.61	$ 51.01

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $17,614,000 for 2010 from $16,316,000 for 2009. This increase is mainly a result of an increase in ad valorem taxes and expenses related to well workovers.

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Production Taxes. Production taxes increased to $13,966,000 for 2010 from $9,797,000 for 2009. This increase was primarily related to a 49% increase in oil and gas revenues as a result of a 27% increase in average realized BOE price received and an 18% increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $38,907,000 for 2010, and consisted of $38,600,000 in depletion on oil and natural gas properties and $307,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $29,225,000 for 2009. This increase was due to an increase in our full cost pool as a result of our capital activities and an increase in our production used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $6,063,000 for 2010 from $4,992,000 for 2009. This $1,071,000 increase was primarily due to a $450,000 increase in franchise taxes, a $200,000 increase in legal expenses and increases related to salaries, benefits expenses partially offset by an increase in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $617,000 for 2010 from $582,000 for 2009.

Interest Expense. Interest expense increased to $2,761,000 for 2010 from $2,309,000 for 2009. This increase was due to an increase in the interest rate paid as well as the recognition of approximately $225,000 in unamortized loan fees associated with the termination of the Bank of America revolving credit facility. Effective September 30, 2010, this facility, along with the term loan with Bank of America, were repaid with borrowings under our new senior secured revolving credit facility with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, entered into on September 30, 2010. This increase in interest expense was partially offset by a decrease in average debt outstanding for the year ended December 31, 2010, as compared to the year ended December 31, 2009. Total debt outstanding under our new revolving credit facility was $49.5 million as of December 31, 2010, as compared to $49.9 million outstanding under our prior facilities with Bank of America as of the same date in 2009. Total weighted debt outstanding under our facilities was $46.9 million for 2010 and $59.9 million for 2009. Until September 30, 2010, amounts borrowed under our term loan and revolving credit facility with Bank of America bore interest of 3.76% and 3.25%, respectively. At December 31, 2010, amounts borrowed under our new revolving credit agreement bore interest at the Eurodollar rate of 3.77%.

Income Taxes. As of December 31, 2010, we had a net operating loss carry forward of approximately $52.4 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2010, a valuation allowance of $54.4 million had been provided for deferred tax assets, with the exception of $628,000 for alternative minimum taxes. We paid $40,000 of state income tax for the year ended December 31, 2010.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our bank and other credit facilities and the issuance of equity securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or our oil and natural gas production. During 2011, we received aggregate net proceeds (before offering expenses) of approximately $307.1 million from the sale of shares of our common stock. During 2010, we received net proceeds (before offering expenses) of approximately $21.6 million from the sale of shares of our common stock.

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Net cash flow provided by operating activities was $158,138,000 for the year ended December 31, 2011 as compared to net cash flow provided by operating activities of $85,835,000 for 2010. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 52% increase in net realized BOE prices and an 18% increase in our net BOE production.

Net cash flow provided by operating activities was $85,835,000 for 2010, as compared to $53,299,000 for 2009. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 27% increase in net realized prices and an 18% increase in our net BOE production.

Net cash used in investing activities for the year ended December 31, 2011 was $323,248,000 as compared to $105,315,000 for 2010. During the year ended December 31, 2011, we spent $287,292,000 in additions to oil and natural gas properties, of which $106,947,000 was spent on our 2011 drilling and recompletion programs, $31,872,000 was spent on expenses attributable to the wells drilled and recompleted during 2010, $8,320,000 was spent on compressors and other facility enhancements, $177,000 was spent on plugging costs, $124,713,000 was spent on lease related costs, primarily the acquisition of leases in the Utica Shale and $3,651,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $3,182,000 was loaned to, and $22,676,000 was invested in, Grizzly during the year ended December 31, 2011, and $3,794,000, $6,009,000 and $2,142,000 was invested in our investments in Tatex III, Bison and Muskie, respectively, during the year ended December 31, 2011. During the year ended December 31, 2011, we used cash from operations and proceeds from our equity offering for our investing activities.

Net cash used in investing activities for 2010 was $105,315,000, as compared to $39,246,000 for 2009. During 2010, we spent $101,644,000 in additions to oil and natural gas properties, of which $51,356,000 was spent on our 2010 drilling and recompletion programs, $16,735,000 was spent on acquisitions in our Niobrara and Permian fields, $11,697,000 was spent on expenses attributable to the wells drilled during 2009, $3,093,000 was spent on our 2009 recompletions, $6,838,000 was spent on compressors and other facility enhancements, $1,425,000 was spent on plugging costs, $771,000 was spent on lease related costs and $3,449,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, we paid $3,719,000 in cash calls to Grizzly during 2010. During 2010, we used cash from operations, borrowings under our credit facilities and proceeds from our equity offering to fund our investing activities.

Net cash provided by financing activities for the year ended December 31, 2011 was $256,539,000 as compared to $20,224,000 for 2010. The 2011 amount provided by financing activities was primarily attributable to the net proceeds of $307,154,000 from our equity offerings and exercise of stock options, partially offset by net principal payments of $49,500,000 on borrowings under our credit facility. The 2010 amount provided by financing activities was primarily attributable to the net proceeds from our equity offerings of $21,358,000.

Net cash provided by financing activities for 2010 was $20,224,000 as compared to net cash used by financing activities of $18,273,000 for 2009. The 2010 amount provided by financing activities is primarily attributable to the net proceeds of $21,358,000 from our equity offering and borrowings of $52,200,000 under our new credit facility, partially offset by principal payments of $49,903,000 on borrowings under our prior credit facilities with Bank of America. We used the net proceeds of our 2010 equity offering to fund the acquisition of our interests in the Niobrara Formation, pay the purchase price for a portion of the additional acreage acquired by us in the Permian Basin in 2010 and for general corporate purposes.

The 2009 amount used by financing activities was primarily attributable to principal payments on borrowings of $18,206,000 under our credit facility with Bank of America, partially offset by $30,000 received from the exercise of stock options.

Credit Facility. On September 30, 2010, we entered into a $100.0 million senior secured revolving credit facility with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, or Amegy Bank, which revolving credit facility initially matured on

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September 30, 2013 and had a borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. On May 3, 2011, we entered into a first amendment to the revolving credit facility with the Bank of Nova Scotia, Amegy Bank, KeyBank National Association, or KeyBank, and Société Générale. Pursuant to the terms of the first amendment, KeyBank and Société Générale were added as additional lenders, the maximum amount of the revolving credit facility was increased to $350.0 million, the borrowing base was increased to $90.0 million, certain fees and rates payable by us under the credit facility were decreased, and the maturity date was extended until May 3, 2015. On October 31, 2011, we entered into additional amendments to our revolving credit facility pursuant to which, among other things, the borrowing base under this facility was increased to $125.0 million. On December 14, 2011, we repaid all outstanding borrowings under this credit facility with a portion of the net proceeds of our equity offering completed on December 5, 2011 pending the application of such proceeds to fund our additional Utica Shale lease acquisitions and for general corporate purposes. Our revolving credit facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guaranteed our obligations under the revolving credit facility.

Advances under our revolving credit facility, as amended, may be in the form of either base rate loans or Eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 1.00% to 2.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its prime rate, and (c) the Eurodollar rate for an interest period of one month plus 1.00%. The interest rate for Eurodollar loans is equal to (1) the applicable rate, which ranges from 2.00% to 3.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the London Interbank Offered Rate for deposits in U.S. dollars. As of December 14, 2011 (the latest date during the year ended December 31, 2011 on which we had borrowings outstanding), amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate (2.26%).

Our revolving credit facility contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in the credit facility. The credit facility also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offering, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with all covenants at December 31, 2011.

In connection with our scheduled spring 2012 borrowing base redetermination completed in February 2012, Scotia Capital has advised us that it has recommended an increase to our borrowing base from the current level of $125.0 million to $150.0 million, subject to the approval of the other banks in the syndicate.

Building Loans. In June 2004, we purchased the office building we occupy in Oklahoma City, Oklahoma, for $3.7 million. One loan associated with this building matured in March 2006 and bore interest at the rate of 6% per annum, while a second loan was scheduled to mature in June 2011. We entered into a new building loan in March 2011 to refinance the $2.4 million outstanding at that time. The new agreement extends the maturity date of the building loan to February 2016 and reduces the interest rate from 6.5% per annum to 5.82% per annum. The new building loan requires monthly interest and principal payments of approximately $22,000 and is collateralized by the Oklahoma City office building and associated land. As of December 31, 2011, approximately $2.3 million was outstanding on this loan.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, to fund Grizzly s delineation drilling program and initial preparation of the Algar Lake facility and for acquisitions, primarily in the Permian Basin, the Niobrara Formation and Utica Shale. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, and (2) explore acquisition and disposition opportunities.

Of our net reserves at December 31, 2011, 56% were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

At December 31, 2011, our booked inventory of prospects included approximately 24 drilling locations at WCBB. The drilling schedule used in our December 31, 2011 reserve report anticipates that all of those wells will be drilled by 2015. During 2011, we recompleted 68 wells and drilled 21 wells, of which 19 were completed as producers, one was non-productive and one was waiting on completion, for an aggregate cost of $42.4 million. From January 1, 2012 through February 20, 2012, we recompleted six existing wells and drilled three new wells at our WCBB field, and at February 20, 2012 we were in the process of drilling two additional wells. We currently intend to recomplete 60 wells and drill 22 to 24 new wells during 2012. Our aggregate drilling and recompletion expenditures for our WCBB field during 2012 are estimated to be approximately $36.0 million to $38.0 million.

In our East Hackberry field, in 2011, we recompleted 24 existing wells and drilled 22 wells, of which 17 were completed as producers, two were non-productive and three were waiting on completion for an aggregate cost of $51.9 million. From January 1, 2012 through February 20, 2012, we recompleted two existing wells and drilled two new wells at our East Hackberry field, and at February 20, 2012 we were in the process of drilling two additional wells. We currently intend to drill 10 to 12 wells and recomplete 10 wells in our East Hackberry field in 2012. Total capital expenditures for our East Hackberry field during 2012 are estimated to be approximately $24.0 million to $26.0 million.

In the Permian Basin, our booked inventory of prospects at December 31, 2011 included 252 gross (124 net) future development drilling locations. During 2011, 39 gross (17 net) wells were drilled on this acreage, of which 35 were completed as producers and four were waiting on completion for an aggregate cost of $38.4 million. From January 1, 2012 through February 20, 2012, two gross (one net) wells were drilled on this acreage and were waiting on completion and at February 20, 2012 one gross (0.5 net) additional well was being drilled. We currently anticipate that our capital requirements to drill a total of 23 to 25 gross (11.5 to 12.5 net) wells and recomplete five gross (2.5 net) wells in the Permian Basin in West Texas will be approximately $23.0 million to $25.0 million in 2012. In an effort to facilitate the development of our Permian Basin and other domestic acreage, in 2011 we acquired a 25% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates four drilling rigs. Our purchase price for this interest was approximately $6.0 million, subject to adjustment. The remaining 75% equity interest is owned by entities controlled by Wexford. Also in 2011, we acquired a 25% interest in Muskie Holdings LLC, or Muskie, which holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand, for $2.1 million. Muskie is controlled by Wexford. The 2012 budgets for Bison and Muskie have not yet been established.

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In the Niobrara Formation in northwestern Colorado, in 2011, we completed a 60 square mile 3-D seismic survey, have received a processed version of the seismic and are selecting future drilling locations. Our total capital expenditures in the Niobrara Formation were approximately $6.8 million in 2011 relating to the seismic survey, drilling three gross (1.5 net) wells and leasehold acquisitions. We currently anticipate that our total capital expenditures in the Niobrara Formation will be approximately $5.0 million to $6.0 million in 2012 to drill five to seven gross wells.

In the Utica shale in Ohio, in 2011, we acquired approximately 98,000 gross (49,000 net) acres for $118.4 million. During 2012, we expect to spend up to an additional $30.0 million to $35.0 million to acquire up to another 27,000 gross (13,500 net) acres. In addition, during 2012, we currently anticipate spending another $72.0 million to $76.0 million to drill 20 gross (ten net) wells.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of December 31, 2011, our net investment in Grizzly was approximately $69.0 million. Our capital requirements in 2012 for this project are estimated to be approximately $40.0 million to $43.0 million, primarily for the expenses associated with the construction of the Algar Lake facility and drilling activity during the 2011-2012 winter drilling season. In addition, in January 2012, Grizzly entered into an agreement to purchase approximately 46,700 acres of oil sands leases in the Athabasca oil sands area for $225.0 million CAD. Our capital contribution obligation to Grizzly for our portion of the purchase price is approximately $56.3 million and will be due at closing of the transaction. We expect to fund this amount with borrowings under our revolving credit facility.

Net capital expenditures in 2011 relating to our interest in Thailand were approximately $2.9 million. Capital expenditures in 2012 relating to our interests in Thailand are expected to be approximately $6.0 million, which we believe will be partially funded from our share of production from the Phu Horm field.

Our total capital expenditures for 2012 are currently estimated to be in the range of $215.0 million to $225.0 million, excluding the acquisition costs of our Utica Shale acreage, Grizzly May River acquisition and any other potential acquisitions. This is up from the $130.0 million spent on 2011 activities due to improved commodity pricing and cost environment. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

We believe that our cash on hand, cash flow from operations and borrowings under our revolving credit facility will be sufficient to meet our normal recurring operating needs and capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling programs, pursue additional acquisitions or accelerate our Canadian oil sands project, we may be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in January 2006. On February 15, 2012, the West Texas Intermediate posted price for crude oil was $101.80 per barrel and the Henry Hub spot market price of natural gas was $2.43 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

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To mitigate the effects of commodity price fluctuations, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials, for the period January 2010 through February 2010. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through December 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from January 2013 through June 2013, we entered into fixed price swaps for 1,000 barrels of oil per day at a weighted average price of $113.20 per barrel. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contracts, we delivered approximately 31% of our 2011 production. Under the 2012 contracts, we have committed to deliver approximately 32% to 35% of our estimated 2012 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

Commitments

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller s (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2011, the plugging and abandonment trust totaled approximately $3.1 million. At December 31, 2011, we have plugged 320 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

The following table sets forth our contractual and commercial obligations at December 31, 2011.

		Payment due by period (1)			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Short-term and long-term debt	$ 2,283,000	$ 141,000	$ 476,000	$ 1,666,000	$
Asset retirement obligations	12,653,000	620,000	1,361,000	792,000	9,880,000
Total	$ 14,936,000	$ 761,000	$ 1,837,000	$ 2,458,000	$ 9,880,000

(1) Does not include estimated interest of $129,000 less than one year, $335,000 1-3 years and $16,000 3-5 years and short-term derivative instruments of $1,601,000 less than one year.

New Accounting Pronouncements

In December 2008, the SEC published a final rule, Modernization of Oil and Gas Reporting. The new rule permits the use of new technologies to determine proved reserves if those technologies have been demonstrated to lead to reliable conclusions about reserve volumes. The new requirements also allow companies to disclose their probable and possible reserves. In addition, the new disclosure requirements require companies to (a) report the independence and qualifications of its reserve preparer, (b) file reports when a third party is relied upon to prepare reserve estimates or conducts a reserve audit, and (c) report oil and gas reserves using an average price based upon the prior 12-month period rather than year end prices. The new requirements were effective for

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annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. We adopted this final rule as of December 31, 2009. The adoption of the rule resulted in a lower price used in reserve calculations and a decrease in 2009 reserves. Updated disclosures are included in Item 2. Properties Proved Oil and Natural Gas Reserves and Note 20 to our consolidated financial statements included in this report.

In January 2010, the FASB issued Accounting Standards Update 2010-03, Oil and Gas Reserve Estimation and Disclosures (currently codified in FASB ASC Topic 932, Extractive Activities Oil & Gas), or FASB ASC 932. The purpose of the amendments in this Update was to align the oil and gas reserve estimation and disclosure requirements of FASB ASC 932 with the requirements in the SEC s final rule, Modernization of Oil and Gas Reporting. The amendments to FASB ASC 932 were effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. We adopted FASB ASC 932 effective December 31, 2009, the impact of which is noted above.

In May 2011, the FASB issued Accounting Standards Update No. 2011-04, Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS, which provides amendments to FASB ASC Topic 820, Fair Value Measurements and Disclosure , or FASB ASC 820. The purpose of the amendments in this update is to create common fair value measurement and disclosure requirements between GAAP and IFRS. The amendments change certain fair value measurement principles and enhance the disclosure requirements. The amendments to FASB ASC 820 are effective for interim and annual periods beginning after December 15, 2011.

In June 2011, the FASB issued Accounting Standards Update No. 2011-05, Comprehensive Income: Presentation of Comprehensive Income, which provides amendments to FASB ASC Topic 220, Comprehensive Income , or FASB ASC 220. The purpose of the amendments in this update is to provide a more consistent method of presenting non-owner transactions that affect an entity s equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in stockholders equity and require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. The amendments to FASB ASC 220 are effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; 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 and natural gas producing regions; and the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or bbl, in December 2008 to a high of $145.31 per barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in

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January 2006. On February 15, 2012, the West Texas Intermediate posted price for crude oil was $101.80 per barrel and the Henry Hub spot market price of natural gas was $2.43 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

For the period January 2010 through February 2010, we were party to forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $54.81 per barrel, before transportation costs and differentials. For the period March 2010 through December 2010, we were party to forward sales contracts for the sale of 2,300 barrels of WCBB production per day at a weighted average daily price of $58.24 per barrel before transportation costs and differentials. In November 2010, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $86.96 per barrel for the period January 2011 through December 2011. For January 2012 through February 2012, we entered into fixed price swaps for 2,000 barrels of oil per day at a weighted average price of $108.00 per barrel. For the period from March 2012 through December 2012, we entered into fixed price swaps for 3,000 barrels of oil per day at a weighted average price of $109.73 per barrel. For the period from January 2013 through June 2013, we entered into fixed price swaps for 1,000 barrels of oil per day at a weighted average price of $113.20 per barrel. Under the 2010 contracts, we delivered approximately 45% of our 2010 production. Under the 2011 contracts, we delivered approximately 31% of our 2011 production. Under the 2012 contracts, we have committed to deliver approximately 32% to 35% of our estimated 2012 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements. At December 31, 2011, we had a net asset derivative position of $1.6 million related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $7.7 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by $7.7 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or Eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the Eurodollar rates are elected, the Eurodollar rates. At December 14, 2011 (the latest date during the year ended December 31, 2011 on which we had borrowings outstanding), amounts borrowed under our revolving credit facility bore interest at the Eurodollar rate of 2.26%. Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $130,000 per year, based on $13.0 million outstanding under our revolving credit facility as of December 14, 2011. As of December 31, 2011, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 following the signature pages of this Report.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Chief Executive Officer and Vice President and Chief Financial Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the

Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Vice President and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2011, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. Based upon our evaluation, our Chief Executive Officer and Vice President and Chief Financial Officer have concluded that as of December 31, 2011, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Management s Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of adequate internal controls over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in *Internal Control Integrated Framework*, management did not identify any material weaknesses in our internal control over financial reporting and concluded that our internal control over financial reporting was effective as of December 31, 2011.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2011 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2011, as stated in their accompanying report.

/s/ James D. Palm	/s/ Michael G. Moore
Name: James D. Palm	Name: Michael G. Moore
Title: Chief Executive Officer	Title: Chief Financial Officer

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation:

We have audited internal control over financial reporting of Gulfport Energy Corporation and Subsidiaries (the Company) as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for 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 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Gulfport Energy Corporation and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2011 and our report dated February 27, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 27, 2012

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information concerning Item 10 Directors, Executive Officers and Corporate Governance, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 11. EXECUTIVE COMPENSATION

For information concerning Item 11 Executive Compensation, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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

For information concerning Item 12 Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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

For information concerning Item 13 Certain Relationships and Related Transactions, and Director Independence, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For information concerning Item 14 Principal Accounting Fees and Services, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

List the following documents filed as part of this report:

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of November 28, 2007, by and among Ambrose Energy I, Ltd. and each of the other persons, which are listed as a party seller, and Windsor Permian (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
2.2	Second Amendment to the Purchase and Sale Agreement, dated as of December 18, 2007, by and among Ambrose Energy I, Ltd., each of the other parties which are listed as a party seller, Windsor Permian and Gulfport (incorporated by reference to Exhibit 2.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 24, 2007).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Form of Warrant Agreement (incorporated by reference to Exhibit 10.4 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.3	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.4	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.5	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
10.1+	Amended and Restated 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.3+	Form of Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.3 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.4+	Employment Agreement, dated as of May 18, 1999 and effective as of June 1, 1999, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.5 of Amendment No. 1 to Form 10-KSB/A, File No. 000-19514, filed by the Company with the SEC on May 11, 2007).
10.5+	Summary of Oral Employment Agreement with James D. Palm (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 7, 2010).

Exhibit Number	Description
10.6	Credit Agreement, dated as of September 30, 2010, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 6, 2010).
10.7	Amendment, dated as of December 24, 2010, to the Credit Agreement by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, and Amegy Bank National Association (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 28, 2010).
10.8	First Amendment, dated May 3, 2011 of Credit Agreement, dated September 30, 2011, by and among the Company, as borrower, the Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, Amegy Bank National Association, KeyBank National Association and Société Générale (incorporated by reference to Exhibit 10.2 of Form 10-Q, File No. 000-19514, filed by the Company with the SEC on May 9, 2011).
10.9	Second Amendment to Credit Agreement, dated as of October 31, 2011, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, Amegy Bank National Association, as syndication agent, KeyBank National Association, as co-documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.2 of Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 4, 2011).
10.10	Third Amendment to Credit Agreement, dated as of October 31, 2011, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, letter of credit issuer and lead arranger, Amegy Bank National Association, as syndication agent, KeyBank National Association and Société Générale, as co-documentation agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.2 of Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 4, 2011).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Ryder Scott Company.
23.4*	Consent of Pinnacle Energy Services, LLC.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
99.2*	Report of Ryder Scott Company.
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.

Exhibit Number	Description
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.
** Furnished herewith, not filed.
+ Management contract, compensatory plan or arrangement.

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SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 27, 2012

GULFPORT ENERGY CORPORATION

By: /s/ JAMES D. PALM
James D. Palm

Chief Executive Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: February 27, 2012	By:	/s/ JAMES D. PALM **James D. Palm** **Chief Executive Officer and Director** **(Principal Executive Officer)**
Date: February 27, 2012	By:	/s/ MIKE LIDDELL **Mike Liddell** **Chairman of the Board and Director**
Date: February 27, 2012	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **Vice President and Chief Financial Officer** **(Principal Financial and Accounting Officer)**
Date: February 27, 2012	By:	/s/ DONALD DILLINGHAM **Donald Dillingham** **Director**
Date: February 27, 2012		