UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2009
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 ☐ No ☒

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (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 ☐ 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. ☒

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 ☐ 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 ☒

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 30, 2009, based on the closing price of the common stock on the NASDAQ Global Select Market on June 30, 2009, the last business day of the registrant's most recently completed second fiscal quarter ($6.85 per share) was $182,710,913.

As of March 1, 2010, 42,697,402 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation's Proxy Statement for the 2010 Annual Meeting of Stockholders are incorporated by reference in Items 9, 10, 11, 12 and 13 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,” “projects,” “predicts,” “potential” 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.

PART I

ITEM 1. DESCRIPTION OF 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. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, 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 2009, at our WCBB field, we recompleted 56 wells and drilled 11 wells for a total cost of approximately $19.6 million as of December 31, 2009. Of our 11 new wells drilled at WCBB in 2009, 10 were completed as producing wells and one was non-productive. During 2010, we currently anticipate drilling 20 wells and recompleting 40 wells at our WCBB field for an estimated aggregate cost of $33.0 to $36.0 million. In December 2009, production at WCBB was 116,637 net barrels of oil equivalent, or BOE, or an average of 3,762 BOE per day, 97% of which was from oil and 3% of which was from natural gas. From January 1, 2010 through February 28, 2010, our average net daily production at WCBB was 3,432 BOE, 98% of which was from oil and 2% of which was from natural gas.

In 2009, at our East Hackberry field, we recompleted five wells and drilled six wells for a total cost of approximately $11.0 million as of December 31, 2009. All wells drilled during 2009 were completed as producing wells. During 2010, we currently anticipate drilling three wells and recompleting five wells for an aggregate estimated cost of $6.0 to $7.0 million. In December 2009, net production at East Hackberry was 13,284 BOE, or an average of 429 BOE per day, 96% of which was from oil and 4% of which was from natural gas. From January 1, 2010 through February 28, 2010, our average net daily production at East Hackberry was 814 BOE, 96% of which was from oil and 4% of which was from natural gas.

In December 2009, net production at West Hackberry was 1,202 BOE, or an average of 39 BOE per day, 100% of which was from oil. From January 1, 2010 through February 28, 2010, our average net daily production at West Hackberry was 44 BOE, 100% of which was from oil.

Effective November 1, 2007, we acquired approximately 4,100 net acres in West Texas in the Permian Basin with production at the time of acquisition from 32 gross wells, predominately from the Wolfcamp formation. In 2008, 31 gross (15.5 net) wells were drilled on this acreage. In 2009, we acquired an additional 4,095 net acres, bringing our total net acreage position in the Permian Basin to approximately 8,200 net acres. During the year ended December 31, 2009, we drilled four gross wells and recompleted three gross wells on this acreage. As of March 1, 2010, three of the four wells had been completed and the other well was awaiting completion. We currently anticipate drilling 24 to 26 gross (12 to 13 net) wells on this acreage in 2010 for an estimated aggregate cost of $15.0 to $17.0 million. In December 2009, net production from our Permian acreage was 17,030 BOE, or an average of 549 BOE per day, 82% of which was from oil and natural gas liquids and 18% of which was from natural gas. From January 1, 2010 through February 28, 2010, our average daily net production from our Permian acreage was 507 BOE per day, 82% of which was from oil and natural gas liquids and 18% of which was from natural gas.

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. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has approximately 527,000 acres under lease and our total net investment in Grizzly was approximately $41.0 million, including a note receivable of $15.9 million, at December 31, 2009. During the 2006/2007, 2007/2008 and 2008/2009 winter delineation drilling seasons, Grizzly drilled an aggregate of 131 core holes and one water supply test well, tested five separate lease blocks and conducted a seismic program. Grizzly recently filed an application in Alberta, Canada for the development of an 11,300 barrel per day oil sand project at Algar Lake, and its currently contemplated 2010 activities relate primarily to initial preparations for this facility.

During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex. The remaining interests in Tatex are owned by entities controlled by Wexford Capital, LP, or Wexford. Affiliates of Wexford beneficially own approximately 36% of our outstanding common stock. Tatex, 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 three 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 one million acres. During 2009, the operator conducted a 3-D seismic survey on this concession. During 2010, we expect to participate in the drilling of two wells.

During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. In 2006, Bakken acquired leases for undeveloped acreage in the Williston Basin area of western North Dakota and eastern Montana. 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 $5.8 million with an effective date of July 1, 2009. As of December 31, 2009, we held approximately 900 net acres and interests in 28 wells, as well as certain wells that might be drilled in the future.

In December 2009, net production from our remaining Bakken acreage was 2,092 BOE, or an average of 67 BOE per day, 97% of which was from oil and natural gas liquids and 3% of which was from natural gas. From January 1, 2010 through February 28, 2010, our average daily net production from our Bakken acreage was 66 BOE per day, 95% of which was from oil and 5% of which was from natural gas.

As of December 31, 2009, we had 19.9 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 $263 million and associated standardized measure of discounted future net cash flows of approximately $240.8 million. 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, 2009 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 and in the Williston Basin.

								Proved Reserves		
	NRI/WI (1)	Productive Wells (2)		Non-Productive Wells		Developed Acreage (3)		Gas	Oil	Total
Field	Percentages	Gross	Net	Gross	Net	Gross	Net	Mboe	Mboe	Mboe
West Cote Blanche Bay Field (4)	80.108/100	95	95	181	181	5,668	5,668	262	5,028	5,290
E. Hackberry Field (5)	79.424/100	18	18	86	86	3,291	3,291	308	2,490	2,798
W. Hackberry Field	87.5/100	3	3	24	24	592	592	—	172	172
Permian Basin	38.075/49.48	64	32	—	—	8,157	4,078	1,816	9,763	11,579
Williston Basin (6)	3.08/4.10	4	1	—	—	2,560	127	2	32	34
Overrides/Royalty Non-operated	Various	32	1	17	2	—	—	1	3	4
Total		216	150	308	293	20,268	13,756	2,389	17,488	19,877

(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes nine gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 68% 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.

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 919 wells drilled as of December 31, 2009, 826 were completed as producing wells. As a result, the field has a historic success rate of 90% for all wells drilled. From the date of our acquisition of WCBB in 1997 through December 31, 2009, we drilled 139 new wells, 16 of which were non-productive, for an 88% success rate. As of December 31, 2009, estimated field cumulative gross production was 190.1 MMBOE and 236.1 billion cubic feet, or Bcf, of gas. Of the 919 wells drilled in WCBB as of December 31, 2009, 86 were producing, 181 were shut-in, nine were producing intermittently and five were being used as salt water disposal wells. The other 638 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 919 wellbores that had been drilled in the field as of December 31, 2009, 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, 2009 included 21 PUD wells. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2012.

Facilities

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

Recent and Future Activity

In 2009, we recompleted 56 wells and drilled 11 wells at WCBB. Of these 11 new wells, 10 were completed as producers, and one was non-productive. As of February 28, 2010, we had recompleted eight wells during 2010. Of the 11 wells drilled in 2009, none were considered deep wells. The ten productive wells, with total depths ranging from 2,500 to 10,325 feet, have approximately 1,077 feet of aggregate apparent net pay. We currently anticipate drilling 20 wells and recompleting 40 wells at WCBB during 2010.

Production Status

In December 2009, production at WCBB was 116,637 net BOE, or an average of 3,762 BOE per day, 97% of which was from oil and 3% of which was from natural gas. From January 1, 2010 through February 28, 2010, our average net daily production at WCBB was 3,432 BOE, 98% of which was from oil and 2% of which was from natural gas.

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 7,738 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.

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 2009 was over 597,172 barrels of oil and 330 Bcf of casinghead gas production. A total of 193 wells have been drilled on our portion of the field. As of December 31, 2009, 18 wells had daily production, 86 were shut-in and two had been converted to salt water disposal wells. The remaining 87 wells had been plugged and abandoned.

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 completed installation of a new production barge at the East Hackberry field in the second quarter of 2007. The barge is designed to have the ability to process on a per day basis approximately 5,000 barrels of liquid, 30 Mmcf of high pressure natural gas, 6.5 Mmcf of low pressure natural gas and 10,000 barrels of salt water.

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 2009 at East Hackberry, we recompleted five wells and drilled four land wells and two wells on water. All of the six wells drilled during 2009 were completed as producing wells. As of February 28, 2010, we had not recompleted or drilled any wells during 2010. We currently intend to drill three land wells and recomplete five wells at East Hackberry during 2010.

Production Status

In December 2009, net production at East Hackberry was 13,284 BOE, or an average of 429 BOE per day, 96% of which was from oil and 4% of which was from natural gas. From January 1, 2010 through February 28, 2010, our average net daily production at East Hackberry was 814 BOE, 96% of which was from oil and 4% of which was from natural gas. Production has increased as a result of the successful drilling and completion of four wells during the fourth quarter of 2009.

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 2009 was 261 MBOE and 140 Bcf of natural gas. There have been 36 wells drilled to date on our portion of West Hackberry. Currently, three are producing, 24 are shut-in and one has been converted to a saltwater disposal well. The remaining eight wells have been plugged and abandoned.

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 December 2009, net production at West Hackberry was 1,202 BOE, or 39 BOE per day. From January 1, 2010 through February 28, 2010, our average net daily production at West Hackberry was 44 BOE and was 100% oil.

Facilities

We have land-based production and processing facilities located at the West Hackberry field and maintain a field office that serves both the East and West Hackberry fields.

Permian Basin (West Texas)

Location and Land

We acquired approximately 4,100 net acres in West Texas (near Midland) in the Permian Basin on December 20, 2007, effective date as of November 1, 2007, from ExL Petroleum, LP and certain other sellers. Subsequently, we acquired an additional 4,095 net acres, bringing our total acreage position to approximately 8,200 net acres as of December 31, 2009. 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 Energy 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, 2009, we hold interests in 64 gross 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. Pinnacle Energy Services, LLC, an independent petroleum engineering firm, has estimated that at December 31, 2009, proved reserves net to our interest in these assets were approximately 11.6 million BOE, of which 12% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 191 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 December 2009, net production from the Permian field was 17,030 BOE, or an average of 549 BOE per day, 82% of which was from oil and natural gas liquids, and 18% of which was from natural gas. From January 1, 2010 through February 28, 2010, our average daily net production from our Permian acreage was 507 BOE per day, 82% of which was from oil and natural gas liquids and 18% of which was from natural gas. As a result of the reduction of drilling, fracing and recompletion activities, production has decreased since year end due to normal production declines.

Facilities

There are typical land oil and 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 2009, four gross (two net) wells were drilled in our Permian acreage. We have identified 191 gross future development drilling locations. We currently expect an estimated 24 to 26 gross (12 to 13 net) wells to be drilled on our acreage in 2010. The wells are expected to be drilled to approximately 10,200 feet.

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, 2009, we held approximately 900 net acres and interests in 28 wells, as well as interests in certain wells that might be drilled in the future.

Production Status

In December 2009, net production from our Bakken acreage was 2,092 BOE, or an average of 67 BOE per day, 97% of which was from oil and natural gas liquids and 3% of which was from natural gas. From January 1, 2010 through February 28, 2010, our average net daily production from this acreage was 66 BOE, of which 95% was from oil and 5% was from natural gas liquids.

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

As a result of the sale transactions described above, we have no activities currently scheduled for 2010 in the Williston Basin.

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 as described in the following table:

Field	Parish	Acreage Working Interest	Overriding Royalty Interests	Producing Wells	Non-Producing Wells
Bayou Long	Iberia	3.125%	0%	0	0
Bayou Penchant	Terrebonne	3.125%	0%	1	6
Bayou Pigeon	Iberia	6.250%	0%	4	5
Deer Island	Terrebonne	6.250%	0%	0	6
Golden Meadow	Lafourche	3.125%	0%	0	1
Napoleonville	Assumption	0%	2.5%	3	0

Thailand. During 2005, we purchased a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex, at a cost of $2.4 million. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, 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 three million acres which includes the Phu Horm Field. During the year ended December 31, 2009 we paid $320,000 in cash calls and received $517,000 in distributions, bringing our total investment in Tatex (including previous investments) to $2.5 million. Our investment is accounted for on the equity method. Tatex 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 northeast Thailand. Phu Horm's initial gross production was approximately 60 million cubic feet per day. For December 2009, net gas production was approximately 83 MMcf per day and condensate production was 452 Bbl's 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 as a member of APICO) in the Phu Horm field is 0.7%. Estimated proved reserves from the Phu Horm field as of December 31, 2008, net to our interest, are 2.739 BCF of gas. Due to the fact that our ownership in the Phu Horm field is indirect and Tatex'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 $3,385,000 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. During the year ended December 31, 2009, we paid $428,000 in cash calls, bringing our total investment in Tatex III to $4,482,000. Currently, we plan to participate in the drilling of two wells during 2010.

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. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the

Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has approximately 527,000 acres under lease and our total net investment in Grizzly was approximately $41.0 million, including a note receivable of $15.9 million, at December 31, 2009. During the 2006/2007, 2007/2008 and 2008/2009 winter delineation drilling seasons, Grizzly drilled an aggregate of 131 core holes and one water supply test well, tested five separate lease blocks and conducted a seismic program. Grizzly recently filed an application in Alberta, Canada for the development of an 11,300 barrel per day oil sand project at Algar Lake, and its currently contemplated 2010 activities relate primarily to initial preparations for the facility.

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 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, other than the production sold under forward sales contracts, 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 $3.45 per barrel for transportation. During 2009, we sold 92% and 7% of our oil production to Shell and Windsor Energy Group, the operator of our Permian wells, respectively, and 45%, 38%, and 16% of our natural gas production to Windsor Energy Group, Chevron and Hilcorp Energy Company, respectively. During 2008, we sold 87% of our oil production to Shell and 11% to Windsor Energy Group, 100% of our natural gas liquids production to Windsor Energy Group, and 60%, 22%, and 16% of our natural gas production to Chevron, Windsor Energy Group, and Hilcorp Energy Company, respectively. During 2007, we sold 99% of our oil production to Shell and 69% and 23% of our natural gas production to Chevron and Hilcorp, 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 prices 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, during 2009, we were party to forward sales contracts for the sale of 825,000 barrels of WCBB production at a weighted average price of $55.01 per barrel before transportation costs. We delivered approximately 49% of our 2009 production under these agreements. Initially, for the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We also entered into 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, for the period September

2009 to December 2009. In 2009, we terminated forward sales contracts for the months of March and May 2009 for an aggregate of approximately $2.0 million. For the period January 2010 through February 2010 we entered into 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. For the period March 2010 through December 2010, we have entered into 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. Under these contracts, we have committed to deliver approximately 45% of our estimated 2010 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 contacts 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 Williston Basin. These states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling 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, and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict 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, 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 to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes."

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.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA or the "Superfund" law, generally imposes joint and several liability, without regard to fault or legality of 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. Under CERCLA and comparable state statutes, such persons may be subject to strict joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, 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 Oil Pollution Act and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into state waters or waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. 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 permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. We believe that we have obtained or applied for and are in substantial compliance with all permits required under the Clean Water Act. Sanctions for failure to comply with Clean Water Act requirement include administrative, civil and criminal penalties, as well as injunctive obligations.

Air Emissions. The federal Clean Air Act, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. 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. These laws and regulations may increase the costs of compliance for some 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 air emissions 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

Our operations are subject to all of the risks normally incident to the production of oil and natural gas, including, but not limited to, blowouts, cratering, pipe failure, casing collapse, oil spills and fires, each of which could result in severe damage to or destruction of oil and natural gas wells, production facilities or other property, or injury or death to persons and wildlife. The energy business is also subject to environmental hazards, such as oil spills, gas leaks, and ruptures and discharge of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage and consequences thereof, including personal injuries and property damage. We currently maintain insurance covering some, but not all of these risks. The occurrence of a significant event that is not fully insured against could have a material adverse effect on our financial position.

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 that is leased to an unrelated third party. 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, 2009, we had 40 employees. Certain of our employees perform management and administrative services for affiliated companies. We are reimbursed by these affiliates for the salaries and benefits of these individuals based on the estimated time they spent working for those affiliates. In addition, in the past, we have also received 100% of the COPAS overhead charges billed to these affiliated companies. For the years ended December 31, 2009 and 2008, expenses reimbursed to us under these arrangements were $0.6 million and $1.4 million, respectively, and are reflected as a reduction in our general and administrative expenses. A Louisiana well servicing company provides all necessary field personnel needed to operate the WCBB and the Hackberry fields.

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.

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, 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, 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 $1.73 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in December 2005. On December 31, 2009, the West Texas Intermediate posted price for crude oil was $79.39 per bbl and the Henry Hub spot market price of natural gas was $5.83 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.

Recently, concerns over inflation, 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 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 in the future to make substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. To date, 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. 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.

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. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has approximately 527,000 acres under lease and our total net investment in Grizzly was approximately $41.0 million, including a note receivable of $15.9 million, at December 31, 2009. During the 2006/2007, 2007/2008 and 2008/2009 winter delineation drilling seasons, Grizzly drilled an aggregate of 131 core holes and one water supply test well, tested five separate lease blocks and conducted a seismic program. Grizzly recently filed an application in Alberta, Canada for the development of an 11,300 barrel per day oil sand project at Algar Lake, and its currently contemplated 2010 activities relate primarily to initial preparations for the facility. This is a complex project and financing has not been secured. This project may not be completed at our estimated cost or at all.

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

The oil and natural gas industry is cyclical, which can result in a shortage of drilling rigs, equipment, supplies and personnel. As a result, 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, supplies, personnel, trucking services, tubulars, fracing 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, Stuart Maier and Randy Wilson, 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, 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.

Our proved reserves and related PV-10 as of December 31, 2009 have been reported under new SEC rules that went into effect on January 1, 2010. The estimates provided in accordance with the new SEC rules may change materially as a result of interpretive guidance that may be released by the SEC.

We have included in this report certain estimates of our proved reserves and related PV-10 at December 31, 2009 as prepared consistent with our and our independent reserve engineers’ interpretations of the new SEC rules relating to disclosures of estimated natural gas and oil reserves. These new rules are effective for fiscal years ending on or after December 31, 2009. These newly adopted rules will require SEC reporting companies to prepare their reserve estimates using revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing. The SEC has not reviewed our reserve estimates under the new rules and has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules. Accordingly, while the estimates of our proved reserves and related PV-10 at December 31, 2009 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

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

Another impact of the new 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 new 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 included in this report represents only estimates based on reports prepared by Netherland, Sewell & Associates, Inc., or NSAI, as of December 31, 2009 with respect to our WCBB field, by Pinnacle Energy Services, LLC, or Pinnacle, with respect to our assets in the Permian Basin in West Texas and by our personnel with respect to our Hackberry fields and our overrides and non-operated interests. 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 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, 2009, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2009. Estimates of reserves as of year-end 2007 and 2008 were prepared using constant prices and costs in accordance with previous guidelines of the SEC based on hydrocarbon prices received on a field-by-field basis as of December 31st of each year. 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 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, 2009, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2009. Estimated discounted future net revenue from reserves as of year-end 2008 and 2007 were prepared using constant prices and costs in accordance with previous guidelines of the SEC as of December 31st of the applicable year. 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, 2009, approximately 65% 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.

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.

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 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 operations are concentrated in Louisiana and our largest field, 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 350 drilling locations on our Louisiana and West Texas 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 and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Operating hazards and uninsured risks may result in substantial losses.

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, pipe failure, abnormally pressured formations 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 and suspension of operations. For example, in October 2006, an accident occurred north of our production facilities in the WCBB field in southern Louisiana involving two contracted vessels that were performing work on our behalf in the field. A tugboat and two barges laden with construction materials ruptured an underwater natural gas pipeline and a subsequent fire damaged the vessels. Six fatalities resulted from the accident. Several lawsuits relating to this incident were filed against us, among other parties. These lawsuits against us have all been settled.

In accordance with 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 also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

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, 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 relating to protection of human health and the environment. These laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and 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 legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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.

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil, natural gas and NGLs that we produce.

Also, on June 26, 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009," or "ACESA," which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80 percent reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions and the Obama Administration has indicated its support of legislation to reduce greenhouse gas emissions through an emission allowance system.

Although it is not possible at this time to predict when the Senate may act on climate change legislation or how any bill passed by the Senate would be reconciled with ACESA, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil, natural gas and NGLs that we produce.

Even if such legislation is not adopted at the national level, more than one-third of the states, either individually or as part of regional initiatives, have begun taking actions to control and/or reduce emissions of greenhouse gases, as have a number of local governments. Although most of the regional and state-level initiatives have to date been focused on large sources of greenhouse gas emissions, such as coal-fired electric power plants, smaller sources of emissions could become subject to greenhouse gas emission limitations, allowance purchase requirements or other restrictions or costs. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and 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 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, other than the production sold under forward sales contracts, 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 $3.45 per barrel for transportation. During 2009, we sold 92% and 7% of our oil production to Shell and Windsor Energy Group, respectively and 45%, 38%, and 16% of our natural gas production to Windsor Energy Group, Chevron and Hilcorp Energy Company, respectively. During 2008, we sold 87% of our oil production to Shell and 11% to Windsor Energy Group, 100% of our natural gas liquids production to Windsor Energy Group, and 60%, 22%, and 16% of our natural gas production to Chevron, Windsor Energy Group, and Hilcorp Energy Company, respectively. During 2007, we sold 99% of our oil production to Shell and 69% and 23% of our natural gas production to Chevron and Hilcorp, 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 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.

We have entered into forward sales contracts 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, during 2009, we were party to forward sales contracts for the sale of 825,000 barrels of WCBB production at a weighted average price of $55.01 per barrel before transportation costs. We delivered approximately 49% of our 2009 production under these agreements. Initially, for the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We also entered into 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, for the period September 2009 to December 2009. In 2009, we terminated forward sales contracts for the months of March and May 2009 for an aggregate of approximately $2.0 million. For the period January 2010 through February 2010 we entered into 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. For the period March 2010 through December 2010, we have entered into 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. Under these contracts, we have committed to deliver approximately 45% of our estimated 2010 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 contacts 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;
- 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 officers and directors together with our largest stockholder beneficially own a significant percentage of our common stock, and their interests may conflict with those of our other stockholders.

As of December 31, 2009, our executive officers and directors, in the aggregate, beneficially owned approximately 3% of our outstanding common stock and Charles E. Davidson, one of our major stockholders, beneficially owned approximately 36% of our outstanding common stock. As a result, these stockholders acting together are 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.

An active trading market for our common stock may not develop or be sustained.

Since July 14, 2006, our common stock has been listed on The NASDAQ Global Select Market under the symbol "GPOR." From February 28, 2006 until that date, our common stock was listed on the NASDAQ National Market. Prior to that date, our common stock was traded on the NASD OTC Bulletin Board under the symbol "GPOR.OB." There is a limited market for our shares. An active trading market may not develop, or if it does, it may not be sustained.

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, 2009, we had a net operating loss, or NOL, carry forward of approximately $55.7 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 March 1, 2010, there were 42,697,402 shares of our common stock issued and outstanding, excluding 59,251 shares of restricted stock awarded under our 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 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.

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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

Recent SEC Rule-Making Activity

In December 2008, the SEC released its final rule for "Modernization of Oil and Gas Reporting." The new 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.

Application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and natural gas than would have resulted under the previous rules. Use of new 12-month average pricing rules at December 31, 2009 resulted in proved reserves of approximately 19,877 Mboe. Use of the old year-end prices rules would have resulted in proved reserves of approximately 20,241 Mboe at December 31, 2009. Accordingly, the total impact of the new price methodology rules resulted in a negative reserve revision of 364 Mboe.

Total proved reserves were 19,877 Mboe at December 31, 2009 and 25,477 Mboe at December 31, 2008. Approximately 7,375 Mboe of this decrease is attributable to our exclusion from proved undeveloped reserves of 81 PUD locations that were not scheduled to be drilled within the next five years in accordance with the new SEC rules.

Evaluation and Review of Reserves.

Reserve estimates at December 31, 2009 were prepared by NSAI with respect to our WCBB field (27% of our proved reserves at December 31, 2009), by Pinnacle with respect to our assets in the Permian Basin in West Texas (58% of our proved reserves at December 31, 2009) and by our personnel with respect to our Hackberry fields and our overriding royalty and non-operated interests (15% of our proved reserves at December 31, 2009).

NSAI and Pinnacle 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 Pinnacle to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical team members meet with NSAI and Pinnacle periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI and Pinnacle 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, which include the verification of input data used by NSAI and Pinnacle, as well as management review and approval.

Our proved reserves to our Hackberry fields and other minority interests are prepared internally by our internal staff of petroleum engineers and geoscience professionals. Our chief reserve engineer 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 including management review and approval.

The following table sets forth our estimated proved reserves at December 31, 2009, 2008 and 2007:

	Year Ended December 31,					
	2009		2008		2007	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved developed	6,165	4,325	7,072	7,187	7,116	6,746
Proved undeveloped	11,323	10,007	14,699	15,048	17,999	17,513
Total (1)	17,488	14,332	21,771	22,235	25,115	24,259

	Year Ended December 31,		
	2009	2008	2007
Total net proved oil and natural gas reserves (Mboe) (1)	19,877	25,477	29,158
PV-10 value (in millions) (2)	$ 263.0	$ 126.2	$ 821.2
Standardized measure (in millions) (3)	$ 240.8	$ 126.2	$ 668.3

(1) Estimates of reserves as of year-end 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, 2009, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2009. Estimates of reserves as of year-end 2008 and 2007 were prepared using constant prices and costs in accordance with previous guidelines of the SEC based on hydrocarbon prices received on a field-by-field basis as of December 31st of the applicable year. 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 dated December 31, 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 2009, using $57.90 per barrel and 3.87 per MMBtu and adjusted by lease for transportation fees and regional price differentials. The estimated future production in our reserve reports dated December 31, 2008 and 2007 is priced using constant year-end pricing of $41.00 per barrel and $5.71 per MMBtu and $92.50 per barrel and $6.80 per MMBtu, respectively, and 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,		
	2009	2008	2007
Standardized measure of discounted future net cash flows	$ 240,774,000	$ 126,240,000	$ 668,295,000
Add: Present value of future income tax discounted at 10%	22,237,000	—	152,949,000
PV-10 value	$ 263,011,000	$ 126,240,000	$ 821,244,000

(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.

The above table does not include proved reserves net to our interest in Tatex of 2.739 Bcf of gas at December 31, 2008. For further discussion of our interest in Tatex, 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, 2009, 2008 and 2007 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 21 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, 2009, our proved undeveloped reserves totaled 11,323 Mboe of oil and 10,007 MMcf of natural gas, for a total of 12,991 Mboe. Approximately 75% of our PUDs at year-end 2009 were located in the Permian Basin, 14% of our PUDs were located in WCBB and 11% were located in our East Hackberry field. Each of these PUDs will be converted from undeveloped to developed as the well begins production. Changes in PUDs that occurred during 2009 were due to:

- Conversion of approximately 402 Mboe attributable to PUDs into proved developed reserves;
- Positive revisions of approximately 458 Mboe in PUDs due to changes in commodity prices; and
- Exclusion of 7,375 Mboe attributable to 81 PUD locations that were not scheduled to be drilled within the next five years.

Costs incurred relating to the development of PUDs were approximately $6.4 million in 2009. Estimated future development costs relating to the development of PUDs are projected to be approximately $47.8 million in 2010, $28 million in 2011, $38.7 million in 2012, $39.5 million in 2013 and $26.1 million in 2014.

All PUD drilling locations are scheduled to be drilled prior to the end of 2014.

As of December 31, 2009, 19.3% of our total proved reserves were classified as proved developed non-producing.

Production, Prices, and Production Costs

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

	2009	2008	2007
Production Volumes:			
Oil (MBbls)	1,531	1,584	1,501
Gas (MMcf)	491	712	816
Natural gas liquids (Gallons)	2,719	2,583	—
Oil equivalents (Mboe)	1,677	1,764	1,637
Average Prices:			
Oil (per Bbl)	$53.29(1)	$83.23(1)	$66.71(1)
Gas (per Mcf)	$ 4.06	$ 9.23	$ 7.40
Natural gas liquids (per Gallon)	$ 0.73	$ 1.26	$ —
Oil equivalents (per Boe)	$51.01	$80.30	$64.86
Production Costs:			
Average production costs (per Boe)	$ 9.73(2)	$12.96(2)	$10.18(2)
Average production taxes (per Boe)	$ 5.84	$ 8.96	$ 7.74
Total production costs (per Boe)	$15.57	$21.92	$17.92

(1) Includes fixed contract prices at a weighted average price of:

June – December 2007	$66.10
January – December 2008	$78.56
January – December 2009	$55.01

Excluding the effect of the fixed price contracts, the average oil price for 2009 would have been $57.98 per barrel and $55.29 per barrel of oil equivalent. The total volume hedged for 2009 represented approximately 49% of our total oil sales volumes for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2008 would have been $97.36 per barrel and $92.98 per barrel of oil equivalent. The total volume hedged for 2008 represented approximately 73% of our total oil sales for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2007 would have been $72.25 per barrel and $69.93 per barrel of oil equivalent. The total volume hedged for 2007 represented approximately 43% of our total oil sales volumes for the year.

(2) Does not include production taxes.

Productive Wells and Acreage

The following table presents our total gross and net productive wells, expressed separately for oil and gas, and the total gross and net developed acres as of December 31, 2009

Field	NRI/WI (1) Percentages	Productive Oil Wells (2) Gross	Net	Productive Gas Wells Gross	Net	Non-Productive Oil Wells Gross	Net	Non-Productive Gas Wells Gross	Net	Developed Acreage (3) Gross	Net	Undeveloped Acreage Gross	Net
West Cote Blanche Bay Field (4)	80.1/100	93	93	2	2	163	163	18	18	5,668	5,668	—	—
E. Hackberry Field (5)	79.4/100	18	18	—	—	86	86	—	—	3,291	3,291	1,579	1,579
W. Hackberry Field	87.5/100	3	3	—	—	24	24	—	—	592	592	—	—
Permian Basin	38.1/49.5	64	32	—	—	—	—	—	—	8,157	4,078	8,190	4,095
Williston Basin (6)	3.1/4.1	4	1	—	—	—	—	—	—	2,560	127	3,920	779
Overrides/Royalty Non-operated	Various	31	1	1	0	15	1	2	1	—	—	—	—
Total		213	148	3	2	288	274	20	19	20,268	13,756	13,689	6,453

(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes nine gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 68% 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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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.

	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	64	62.5	58	56.5	62	62
Dry	—	—	—	—	—	—
Total	64	62.5	58	56.5	62	62
Development:						
Productive	25	18	69	27	23	23
Dry	1	1	—	—	3	3
Total	26	19	69	27	26	26
Exploratory:						
Productive	1	1	—	—	9	9
Dry	—	—	1	1	3	3
Total	1	1	1	1	12	12

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 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 case is in the early stages of discovery.

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 February 10, 2010, we filed a motion to be dismissed from the proceeding for lack of personal jurisdiction, which motion is pending. This state court proceeding is in its initial stages.

On July 27, 2007, Robotti & Company, LLC filed a putative class action lawsuit in the Court of Chancery for the State of Delaware in and for Kent County, Delaware. The original complaint alleged a breach of fiduciary duty by us and our then present directors in connection with the pricing of our 2004 rights offering. Plaintiff filed an amended complaint on January 15, 2008, and we filed a motion to dismiss in early February 2008 and filed the brief in support of such motion on April 29, 2008. The court held a hearing on October 3, 2008, ultimately deciding to allow the plaintiff to file a second amended complaint. Plaintiff filed its second amended complaint December 22, 2008, which sets forth class action and derivative claim allegations that our then present directors breached their fiduciary duty in connection with the pricing of the 2004 rights offering. The defendants filed their motion to dismiss on January 19, 2009 and their brief in support of such motion on February 20, 2009. Briefing by the parties concluded on April 6, 2009, oral arguments on the motion were heard by the court on April 22, 2009 and on January 14, 2010, the court issued an opinion granting defendants' motion to dismiss and entered an order dismissing the case with prejudice.

Due to the current stages of the LDR and Cudd 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. RESERVED

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
2008		
First Quarter	$19.41	$10.16
Second Quarter	17.67	10.43
Third Quarter	17.07	9.00
Fourth Quarter	10.03	2.87
2009		
First Quarter	$ 5.20	$ 1.50
Second Quarter	7.65	2.23
Third Quarter	8.99	5.23
Fourth Quarter	11.89	7.25
2010		
First Quarter (through February 26, 2010)	$12.68	$ 8.89

On February 26, 2010, the last reported sale price of our common stock on The NASDAQ Global Select Market was $9.80.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Holders of Record

At the close of business on March 2, 2010, there were 358 stockholders of record holding 42,697,402 shares of our outstanding common stock. There were approximately 7,397 beneficial owners of our common stock as of March 2, 2010.

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, 2009, December 31, 2008 and December 31, 2007 and the selected consolidated balance sheet data at December 31, 2009 and December 31, 2008 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, 2006 and December 31, 2005 and the selected consolidated balance sheet data at December 31, 2007, December 31, 2006 and December 31, 2005 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,				
	2009	2008	2007	2006	2005
Selected Consolidated Statements of Operations Data:					
Revenues	$85,262,000	$ 141,217,000	$105,838,000	$60,390,000	$27,559,000
Costs and expenses:					
Lease operating expenses	16,316,000	22,856,000	16,670,000	10,670,000	7,654,000
Production taxes	9,797,000	15,813,000	12,667,000	7,366,000	3,622,000
Depreciation, depletion and amortization	29,225,000	42,472,000	29,681,000	12,652,000	4,789,000
Impairment of oil and natural gas properties	—	272,722,000	—	—	—
General and administrative	4,992,000	6,843,000	5,802,000	3,251,000	1,561,000
Accretion expense	582,000	560,000	554,000	596,000	516,000
	60,912,000	361,266,000	65,374,000	34,535,000	18,142,000
Income (Loss) from Operations	24,350,000	(220,049,000)	40,464,000	25,855,000	9,417,000
Other (Income) Expense:					
Interest expense	2,309,000	4,762,000	3,091,000	1,956,000	250,000
Interest expense—preferred stock	—	—	—	—	272,000
Insurance recoveries	(1,050,000)	(769,000)	—	(3,601,000)	(1,710,000)
Settlement of fixed price contracts	—	(39,000,000)	—	—	—
Interest income	(564,000)	(540,000)	(523,000)	(308,000)	(290,000)
	695,000	(35,547,000)	2,568,000	(1,953,000)	(1,478,000)
Income (Loss) before Income Taxes	23,655,000	(184,502,000)	37,896,000	27,808,000	10,895,000
Income Tax Expense	28,000	—	121,000	—	—
Net Income (Loss)	23,627,000	(184,502,000)	37,775,000	27,808,000	10,895,000
Net Income (Loss) Available to Common Stockholders	$23,627,000	$(184,502,000)	$ 37,775,000	$27,808,000	$10,895,000
Net Income (Loss) Per Common Share—Basic:	$ 0.55	$ (4.33)	$ 1.03	$ 0.85	$ 0.36
Net Income (Loss) Per Common Share—Diluted:	$ 0.55	$ (4.33)	$ 1.01	$ 0.82	$ 0.34

	At December 31,				
	2009	2008	2007	2006	2005
Selected Consolidated Balance Sheet Data:					
Total assets	$ 227,344,000	$ 221,873,000	$ 419,137,000	$ 195,151,000	$ 111,820,000
Total debt, including current maturity	$ 52,428,000	$ 70,731,000	$ 66,533,000	$ 37,691,000	$ 10,200,000
Total liabilities	$ 102,293,000	$ 107,772,000	$ 115,015,000	$ 71,342,000	$ 27,493,000
Stockholders' equity	$ 125,051,000	$ 114,101,000	$ 304,122,000	$ 123,809,000	$ 84,327,000

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. 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.

2009 Developments

- Oil and natural gas revenues decreased 40% to $85.6 million for the year ended December 31, 2009 from $141.7 million for 2008.
- Net income increased to $23.6 million for the year ended December 31, 2009 from a loss of $184.5 million for the year ended December 31, 2008.
- Production decreased 5% to 1,677,474 BOE for the year ended December 31, 2009 from 1,764,053 BOE for 2008.
- During 2009, we drilled 27 wells and recompleted 64 wells. Of our 27 new wells drilled, 22 were completed as producing wells, one was non-productive and four are waiting on completion.
- We sold approximately 18,000 net acres in the Bakken for $18.8 million.

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. 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. 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 $17.5 million at December 31, 2009 and $22.5 million at December 31, 2008. These costs are reviewed periodically 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 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 $272,722,000 for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids continue to decrease, 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, 2009.

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., Pinnacle Energy Services, LLC and to a lesser extent our personnel have prepared reserve reports of our reserve estimates 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. As such, 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. 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, 2009, a valuation allowance of $73.2 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, during 2009, we were party to forward sales contracts for the sale of 825,000 barrels of WCBB production at a weighted average price of $55.01 per barrel before transportation costs. We delivered approximately 49% of our 2009 production under these agreements. Initially, for the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We also entered into 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, for the period September 2009 to December 2009. In 2009, we terminated forward sales contracts for the months of March and May 2009 for an aggregate of approximately $2.0 million. For the period January 2010 through February 2010 we entered into 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. For the period March 2010 through December 2010, we have entered into 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. Under these contracts, we have committed to deliver approximately 45% of our estimated 2010 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 contacts are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, "*Derivatives and Hedging,*" 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:

	2009	2008	2007
Production Volumes:			
Oil (MBbls)	1,531	1,584	1,501
Gas (MMcf)	491	712	816
Natural gas liquids (Gallons)	2,719	2,583	—
Oil equivalents (Mboe)	1,677	1,764	1,637
Average Prices:			
Oil (per Bbl)	$53.29(1)	$83.23(1)	$66.71(1)
Gas (per Mcf)	$ 4.06	$ 9.23	$ 7.40
Natural gas liquids (per Gallon)	$ 0.73	$ 1.26	$ —
Oil equivalents (per Boe)	$51.01	$80.30	$64.86
Production Costs:			
Average production costs (per Boe)	$ 9.73(2)	$12.96(2)	$10.18(2)
Average production taxes (per Boe)	$ 5.84	$ 8.96	$ 7.74
Total production costs (per Boe)	$15.57	$21.92	$17.92

(1) Includes fixed contract prices at a weighted average price of:

June – December 2007	$66.10
January – December 2008	$78.56
January – December 2009	$55.01

Excluding the effect of the fixed price contracts, the average oil price for 2009 would have been $57.98 per barrel and $55.29 per barrel of oil equivalent. The total volume hedged for 2009 represented approximately 49% of our total oil sales volumes for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2008 would have been $97.36 per barrel and $92.98 per barrel of oil equivalent. The total volume hedged for 2008 represented approximately 73% of our total oil sales for the year. Excluding the net effect of the fixed price contracts, the average oil price for 2007 would have been $72.25 per barrel and $69.93 per barrel of oil equivalent. The total volume hedged for 2007 represented approximately 43% of our total oil sales volumes for the year.

(2) Does not include production taxes.

From 2008 to 2009, our net equivalent oil production decreased 5% from 1,764,000 barrels to 1,677,000 barrels due to our reduced drilling activity and normal production declines. From 2007 to 2008, our net oil equivalent production increased 8% from 1,637,000 barrels to 1,764,000 barrels due primarily to continued drilling and recompletion activities. We currently estimate that our 2010 production will be between 1,850,000 and 2,050,000 BOE. However, such estimate may change based on the changing economic climate and unforeseen events, such as hurricanes.

Comparison of the Years Ended December 31, 2009 and December 31, 2008

We reported net income of $23,627,000 for the year ended December 31, 2009, as compared to a net loss of $184,502,000 for the year ended December 31, 2008. This net income is primarily attributable to a 29% decrease in lease operating expenses, a 27% decrease in general and administrative expenses and a 38% decrease in production taxes, partially offset by a 36% decrease in realized BOE prices to $51.01 from $80.30 and a 5% decrease in net production to 1,677,474 BOE. In addition, the net loss for 2008 was primarily attributable to an impairment charge of $272,722,000 related to the drastic decline in oil and gas prices. Further, we had $1,050,000 of insurance proceeds received during the year ended December 31, 2009 compared to insurance proceeds of $769,000 received during 2008.

Oil and Gas Revenues. For the year ended December 31, 2009, we reported oil and natural gas revenues of $85,576,000 as compared to oil and natural gas revenues of $141,650,000 during 2008. This $56,074,000, or 40%, decrease in revenues is primarily attributable to a 36% decrease in realized BOE prices to $51.01 from $80.30 and a 5% decrease in net production to 1,677,474 BOE for the year ended December 31, 2009 from 1,764,053 BOE for the year ended December 31, 2008.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2009 and December 31, 2008:

	Year Ended December 31,	
	2009	**2008**
Oil production volumes (MBbls)	1,531	1,584
Gas production volumes (MMcf)	491	712
Natural gas liquids production volumes (Gallons)	2,719	2,583
Oil equivalents (Mboe)	1,677	1,764
Average oil price (per Bbl)	$53.29	$83.23
Average gas price (per Mcf)	$ 4.06	$ 9.23
Average natural gas liquids (per gallon)	$ 0.73	$ 1.26
Oil equivalents (per Boe)	$51.01	$80.30

Lease Operating Expenses. Lease operating expenses not including production taxes decreased to $16,316,000 for 2009 from $22,856,000 for 2008. This decrease is mainly a result of a decrease in contract labor expenses, a decrease in workovers, compressor and other equipment rentals and repairs, a decrease in the cost of chemicals and supplies and a decrease in personal property taxes. In addition, the lease operating expenses for 2008 included $3,408,000 of unreimbursed expenses related to hurricane repairs as compared to approximately $23,000 of unreimbursed expenses related to hurricane repairs in 2009.

Production Taxes. Production taxes decreased to $9,797,000 for 2009 from $15,813,000 for 2008. This decrease was primarily related to a 40% decrease in oil and gas revenues mainly as a result of the decrease in the average realized BOE price received.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased to $29,225,000 for 2009, and consisted of $28,939,000 in depletion on oil and natural gas properties and $286,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $42,472,000 for 2008. This decrease was due primarily to the reduction in the book value of our oil and gas properties used to calculate depreciation, depletion and amortization expense. This reduction resulted from the drop in commodity prices reflected as of December 31, 2008 and the resulting reduction in our proved reserves which caused us to recognize a ceiling test impairment to our full cost pool of $272,722,000 for the year ended December 31, 2008.

Impairment of Oil and Gas Properties. We use the full cost method of accounting for oil and gas properties and are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of our 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 of January through December 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 our 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 write-down is required. There was no impairment charge for the year ended December 31, 2009. As a result of the drop in commodity prices on December 31, 2008, we recognized a ceiling test impairment of $272,722,000 for the year ended December 31, 2008.

General and Administrative Expenses. Net general and administrative expenses decreased to $4,992,000 for 2009 from $6,843,000 for 2008. This $1,851,000 decrease was due primarily to reductions in franchise taxes as a result of the impairment mentioned in the depreciation, depletion and amortization section above which reduced our net assets used to calculate franchise taxes, a reduction in stock based compensation expenses, reductions in payroll costs including payroll taxes and related benefits mainly due to decreases in the total number of employees partially offset by a decrease in general and administrative reimbursements from our affiliates and a decrease in general and administrative overhead related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense increased slightly to $582,000 for 2009 from $560,000 for 2008.

Interest Expense. Interest expense decreased to $2,309,000 for 2009 from $4,762,000 for 2008 due to a decrease in average debt outstanding and lower interest rates on amounts borrowed under our facilities with Bank of America. Total debt outstanding under our facilities with Bank of America was $49.9 million as of December 31, 2009 and $68.1 million as of the same date in 2008. Total weighted debt outstanding under our facilities with Bank of America was $59.9 million for 2009 and $84.2 million for 2008. As of December 31, 2009, amounts borrowed under our revolving credit facility and our two term loans with Bank of America bore interest of 3.73%, 4.23% and 3.25%, respectively.

Income Taxes. As of December 31, 2009, we had a net operating loss carry forward of approximately $55.7 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, 2009, a valuation allowance of $73.2 million had been provided for deferred tax assets, as the Company has historically had non-taxable income and has future projections of no taxable income during the carryforward period, with the exception of $533,000 related to alternative minimum taxes. We had $28,000 of state income tax expense for the year ended December 31, 2009.

Comparison of the Years Ended December 31, 2008 and December 31, 2007

We reported a net loss of $184,502,000 for the year ended December 31, 2008, compared to net income of $37,775,000 for the year ended December 31, 2007. This net loss was primarily attributable to an impairment charge of $272,722,000 related to the drastic decline in oil and gas prices, partially offset by a $39.0 million gain from the sale in December 2008 of all of our then existing 2009 fixed price contracts. Excluding the effect of the impairment, our net income increased 133% due primarily to (1) a 8% increase in net production to 1,764,053 BOE for the year ended December 31, 2008 from 1,636,902 BOE for 2007, (2) a 25% increase in the average oil price received to $83.23 per barrel for the year ended December 31, 2008 from $66.71 per barrel for 2007 and (3) a $39.0 million gain from the sale in December 2008 of all of our then existing fixed price contracts.

Oil and Gas Revenues. For the year ended December 31, 2008, we reported oil and gas revenues of $141,650,000, compared to oil and gas revenues of $106,163,000 during 2007. This 33% increase in revenues is mainly attributable to an 8% increase in net production to 1,764,053 BOE for the year ended December 31, 2008 from 1,636,902 BOE for 2007 and a 25% increase in the average oil price received to $83.23 per barrel for the year ended December 31, 2008 from $66.71 per barrel for 2007. This increase in oil and natural gas production was the result of production from our 2008 drilling programs and the acquisition of the Permian wells in December 2007. Production in 2008 was adversely affected by the damage caused by Hurricane Ike with production not fully restored until December, 2008. We estimate that approximately 170,000 barrels of oil equivalents production were deferred to other periods.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2008 and December 31, 2007:

	Year Ended December 31,	
	2008	2007
Oil production volumes (MBbls)	1,584	1,501
Gas production volumes (MMcf)	712	816
Natural gas liquids production volumes (Gallons)	2,583	—
Oil equivalents (Mboe)	1,764	1,637
Average oil price (per Bbl)	$83.23	$66.71
Average gas price (per Mcf)	$ 9.23	$ 7.40
Average natural gas liquids (per gallon)	$ 1.26	$ —
Oil equivalents (per Boe)	$80.30	$64.86

Lease Operating Expenses. Lease operating expenses, or LOE, excluding the effects of hurricane related costs and production taxes, increased to $19,448,000 for 2008 from $16,670,000 for 2007. The increase in ongoing LOE was mainly due to $2,700,000 of LOE related to the Permian properties acquired in December 2007. In addition, there were also increases in personal property taxes and repairs to compressors and other equipment in our operating area along the Louisiana Gulf Coast. Included in total LOE of $22,856,000 before production taxes is $3,408,000 of hurricane related LOE costs incurred during 2008.

Production Taxes. Production taxes increased to $15,813,000 for 2008 from $12,667,000 for 2007. This increase was directly related to a 33% increase in oil and gas revenues as a result of the 24% improvement in the price received per barrel of oil equivalent and an 8% increase in production for 2008 as compared to 2007.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $42,472,000 for the year ended December 31, 2008, and consisted of $42,194,000 in depletion on oil and natural gas properties and $278,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $29,681,000 for the year ended December 31, 2007, which consisted of $29,220,000 in depreciation on oil and natural gas properties and $461,000 in depreciation of other property and equipment. This increase was due primarily to an increase in our oil and natural gas property costs associated with our 2008 drilling program, an increase in our oil and gas production for the period and a decrease in our total oil and gas reserve volumes.

Impairment of Oil and Gas Properties. We use the full cost method of accounting for oil and gas properties and are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of our 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 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 our 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 write-down is required. As a result of the drop in commodity prices on December 31, 2008, we recognized a ceiling test impairment of $272,722,000 for the year ended December 31, 2008. This impairment however will reduce future depletion expense. There was no impairment charge for the year ended December 31, 2007.

General and Administrative Expenses. Net general and administrative expenses increased to $6,843,000 for 2008 from $5,802,000 for 2007. This $1,041,000 increase was due primarily to an $832,000 increase in franchise taxes as a result of an increase in total assets and shares outstanding and slight increases in audit fees and insurance costs.

Accretion Expense. Accretion expense increased slightly to $560,000 for 2008 from $554,000 for 2007, due to a larger obligation at the beginning of 2008 compared to the beginning of 2007, resulting from the addition of future abandonment obligations on new wells drilled during 2007.

Interest Expense. Interest expense increased to $4,762,000 for 2008 from $3,091,000 for 2007 due to an increase in average debt outstanding. Total weighted debt outstanding under our facilities with Bank of America was $84.2 million for 2008 as compared to $33.2 million for 2007.

Settlement of Fixed Price Contracts. In December 2008, we terminated all of our then existing 2009 fixed price contracts. Through the termination of these contracts, we received a $39.0 million payment during the fourth quarter of 2008, and in accordance with FASB ASC 815, these amounts were recognized into earnings during the fourth quarter of 2008, the period in which the fixed price contracts were settled. There was not a termination of any fixed price contracts during the year ended December 31, 2007.

Income Taxes. As of December 31, 2008, we had a net operating loss carry forward of approximately $60 million, in addition to numerous temporary differences, which gave rise to a deferred tax asset. Periodically, management performs a forecast of our future 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, 2008, a valuation allowance of $81.9 million had been provided for our entire net deferred tax asset, with the exception of $653,000 related to alternative minimum taxes.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, the issuance of equity securities and borrowings under our bank and other credit facilities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and gas production. In addition, during 2009, we also received proceeds from the sale of Bakken assets.

Net cash flow provided by operating activities was $53,299,000 for 2009, as compared to $135,323,000 for 2008. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 36% decrease in net realized prices and a 5% decrease in our net BOE production.

Net cash flow provided by operating activities was $135,323,000 for 2008, as compared to net cash flow provided by operating activities of $68,902,000 for 2007. The increase of $66,421,000 in 2008 was primarily the result of the termination in December 2008 of our then existing 2009 fixed price contracts for $39,000,000, an increase in cash receipts from our oil and gas purchasers due to higher prices received for oil production and an 8% increase in net production, partially offset by increase in cash paid for lease operating expenses and production taxes.

Net cash used in investing activities for 2009 was $39,246,000, as compared to $136,823,000 for 2008. During the year ended December 31, 2009, we spent (a) $49,533,000 in additions to oil and natural gas properties, of which $20,296,000 was spent on our 2009 drilling and recompletion programs, $14,255,000 was spent on costs attributable to the wells drilled during 2008, $3,719,000 was spent on our 2008 recompletions, $1,191,000 was spent on barges and other facility enhancements, $866,000 was spent on plugging and abandonment activities, $2,853,000 was spent on lease related costs and $1,744,000 was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses, and (b) $3,813,000 on our investment in Tatex III and we loaned $4,377,000 to Grizzly. In May, September and December 2009, we received aggregate net proceeds of approximately $18,286,000 from our sale of properties in the Bakken. During the year ended December 31, 2009, we used cash from operations and proceeds from the sale of Bakken properties to fund our investing activities.

Net cash used in investing activities for 2008 was $136,823,000, as compared to $240,733,000 for 2007. During the year ended December 31, 2008, we spent $126,030,000 in additions to oil and natural gas properties, of which $77,074,000 was spent on our 2008 drilling and recompletion program, $27,131,000 was attributable to the wells drilled or recompleted during 2007, $4,665,000 was spent on compressors, $3,200,000 was spent on facilities, $1,148,000 was spent on plugging activities, $1,933,000 was spent on lease related costs primarily in the Bakken, $1,128,000 was spent on our Belize activities, $841,000 was spent on a new storage barge with the remainder attributable mainly to capitalized general and administrative expenses. In addition, during the year ended December 31, 2008, we received cash distributions of $862,000 from Tatex Thailand II and we made cash investments of $885,000 in Tatex Thailand III and $10,670,000 in Grizzly. We used cash from operations and borrowings under our credit facility to fund our investing activities in 2008.

Net cash used by financing activities for 2009 was $18,273,000, which amount is primarily attributable to principal payments of $18,206,000 under our credit agreement with Bank of America.

Net cash provided by financing activities for 2008 was $4,680,000, as compared to $167,968,000 for 2007. The 2008 amount is primarily attributable to $30,000,000 of borrowings under our line of credit, mostly offset by repayments on the line. The 2007 amount provided by financing activities is primarily attributable to borrowings of $76,000,000 under our credit facility with Bank of America and aggregate proceeds of approximately $138,258,000 from the sale of shares of our common stock in February 2007, May 2007, July 2007 and December 2007, after deducting the underwriting discount and offering expenses, and $868,000 from the exercise of stock options. Net proceeds were used to pay down $46,328,000 of outstanding existing debt under our credit facility with Bank of America, fund substantially all of the purchase price for the acquisition of our interest in certain strategic assets in Upton County, Texas in the Permian Basin and for other general corporate purposes.

Credit Facility. In March 2005, we entered into a three-year secured revolving credit agreement, as amended, with Bank of America, N.A. providing for a revolving credit facility. Borrowings under the credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. Effective July 19, 2007, the credit facility increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. In connection with our acquisition of strategic assets in West Texas in the Permian Basin, effective as of December 20, 2007, our borrowing base under the revolving credit facility increased from $60.0 million to $90.0. In addition, the maturity date was extended from March 31, 2009 to March 31, 2010. On August 31, 2009, the lender completed its periodic redetermination of our borrowing base giving consideration to our year-end 2008 and mid-year 2009 reserve information and then current bank pricing decks, among other factors. As a result of this redetermination, our available borrowing base was reset at $45.0 million, primarily in response to significant declines in commodity prices. Our outstanding principal balance at the effective time of this redetermination was approximately $59.0 million. Amounts borrowed under the credit facility bear interest at the Eurodollar rate plus 3.50% (3.73% at December 31, 2009). The approximately $14.0 million of outstanding borrowings under our credit facility in excess of the new borrowing base was converted into a term loan as of August 31, 2009. An initial $2.0 million payment was made on the term loan at that time and we agreed to make additional monthly payments of $1.0 million commencing on September 30, 2009, with all unpaid amounts due on March 31, 2010.

Outstanding borrowings under the term loan accrue interest at the Eurodollar Rate (as defined in the credit agreement) plus 4% (4.23% at December 31, 2009) or, at our option, at the base rate (which is the highest of the lender's prime rate, the Federal funds rate plus 1/2 of 1%, and the one-month Eurodollar Rate plus 1%) plus 3%. Effective August 31, 2009, we also agreed to adjustments in the commitment fees, interest rates for revolving loans and fees for letters of credit under our credit facility. Specifically, we agreed to pay (a) commitment fees ranging from 0.5% to 0.625% (an increase from 0.15% to 0.25%), (b) margin interest rates ranging from 2.75% to 3.50% for Eurodollar loans (an increase from 1.25% to 2.0%), (c) margin interest rates ranging from 1.75% to 2.5% for base rate loans (an increase from 1.25% to 2.0%), and (d) letter of credit fees at the margin interest rates for Eurodollar loans, in each case based on our utilization percentage. In addition, we agreed to limitations on certain dispositions and investments by us, and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events.

Effective December 31, 2009, we entered into the amended and restated credit agreement with Bank of America, N.A., as administrative agent, and the other lenders from time to time party thereto. The restated credit agreement amended and restated our original 2005 credit agreement primarily to reflect the subsequent amendments thereto and to extend the maturity date of the revolving loan under our original 2005 credit agreement with Bank of America, N.A. from March 31, 2010 to April 1, 2011. The restated credit agreement did not alter the March 31, 2010 maturity date of the term loan outstanding under the original 2005 credit agreement. Our obligations under the restated credit agreement are guaranteed by our subsidiaries.

The restated credit agreement contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period may not be greater than 2.00 to 1.00; and (b) 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, 2009. As we have historically, we continue to make all interest payments on time.

As of December 31, 2009, approximately $45.0 million was outstanding under the revolving credit facility and $2.0 million was outstanding under the term loan, which are included in long-term debt, net of current maturities and current maturities of long-term debt, respectively, on the accompanying consolidated balance sheet. As of March 1, 2010, approximately $45.0 million was outstanding under the revolving credit facility and the term loan had been paid in full. We have used the proceeds of our borrowings under the credit facility for the development of our oil and natural gas properties and other capital expenditures, acquisition opportunities and for other general corporate purposes.

On July 10, 2006, we entered into a $5.0 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. Amounts borrowed bear interest at Bank of America prime (3.25% at December 31, 2009). We make quarterly interest payments on amounts borrowed under the agreement. Our obligations under the agreement are collateralized by a lien on the compressor units. As of December 31, 2009, approximately $2.9 million was outstanding under this agreement, of which $714,000 and $2.2 million are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on our accompanying consolidated balance sheet.

Building Loans. We had three loans associated with two of our buildings. One loan, in the original principal amount of $115,000, related to a building in Lafayette, Louisiana, that we purchased in 1996 to be used as our Louisiana headquarters. This loan bore interest at the rate of 5.75% per annum. We repaid this loan in full during the third quarter of 2007. In addition, in June 2004 we purchased the office building we occupy in Oklahoma City, Oklahoma for $3.7 million. One of the two loans associated with this building, with an original principal amount of $389,000, matured in March 2006 and bore interest at a rate of 6% per annum. The other loan associated with this building, with an original principal amount of $3.0 million, matures in June 2011 and bears interest at a rate of 6.5% per annum. As of December 31, 2009, approximately $2.5 million was outstanding on this loan. The remaining building loan requires monthly interest and principal payments and is collateralized by the respective land and buildings.

Capital Expenditures. Our recent capital commitments have been primarily for the development of our proved reserves, to increase our net acreage position in Grizzly and fund Grizzly's delineation drilling program and for acquisitions, primarily our acquisitions in the Permian Basin. Our strategy, subject to economic and industry conditions, 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. We have upgraded our infrastructure and our existing facilities in Southern Louisiana with the goal of increasing operating efficiencies and volume capacities and lowering lease operating expenses. These upgrades were also intended to better enable our facilities to withstand future hurricanes with less damage. Additionally, we completed the reprocessing of 3-D seismic data in one of our principal properties, WCBB. The reprocessed data enables our geophysicists to continue to generate new prospects and enhance existing prospects in the intermediate zones in the field, thus creating a portfolio of new drilling opportunities. In addition, with our acquisition of strategic assets in the Permian Basin in West Texas, we are required to pay 50% of all drilling costs for drilling activity on such properties. To combat significant declines in the commodity prices during the second half of 2008, management undertook a series of actions aimed at reducing capital spending and operating costs. As a result, we reduced our drilling and other capital activities to a minimum in the fourth quarter of 2008, releasing all rigs in Southern Louisiana and the Permian and only selectively participating in wells in the Bakken. During 2009, we were not bound by lease obligations and long term capital commitments relating to the exploration or development of our oil and gas properties. As a result of the then current economic conditions, we initially reduced our estimated capital activities and aggressively sought price concessions from our service providers until such time costs were reduced to more appropriate levels. Currently, our AFE costs have been reduced by 35% to 40% since 2008. As a result of the improvements in commodity prices and reductions in costs, we currently intend to expand our 2010 drilling activities.

In our December 31, 2009 reserve reports, 65% of our net reserves 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.

Our inventory of prospects includes approximately 21 proved undeveloped drilling locations at WCBB. The drilling schedule used in our December 31, 2009 reserve report anticipates that all of those wells will be drilled by 2012. From January 1, 2010 through March 1, 2010, we recompleted eight existing wells at our WCBB field. We currently intend to spend a total of approximately $33.0 to $36.0 million to drill 20 wells and recomplete 40 wells in our WCBB field during 2010.

In our East Hackberry field, we intend to drill three land wells during 2010. Total capital expenditures for our East Hackberry field during 2010 are estimated at $6.0 to $7.0 million.

From January 1, 2010 through March 1, 2010, two gross wells were drilled in our Permian acreage. We currently anticipate that our capital requirements for our properties in the Permian Basin in West Texas will be approximately $15.0 to $17.0 million during 2010. We have identified 191 gross proved undeveloped (95.5 net) future development drilling locations. We currently expect that approximately 12 to 13 net wells will be drilled on this acreage in 2010.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of December 31, 2009, our net investment in Grizzly was approximately $41.0 million, including a note receivable of $15.9 million. Capital requirements in 2010 for this project are estimated to be approximately $5.0 million, primarily for the expenses associated with initial preparations of the Algar Lake facility.

Capital expenditures in 2010 relating to our interest in Thailand are expected to be approximately $750,000, which we believe will be mostly offset from our share of production from the Phu Horm field.

Due to our sale transactions in 2009, we expect no capital expenditures in 2010 relating to our interest in the Bakken Shale in the Williston Basin.

Our total capital expenditures for 2010 are currently estimated to be $56.0 to $62.0 million. This is an increase from the $45.2 million spent in 2009 as we intend to expand our activities as a result of the improved commodity pricing and reduced cost environment. In addition, through our cost reduction initiative, AFE costs have been reduced by 35% to 40% from the costs quoted in 2008. We intend to monitor pricing and cost developments during 2010 and make adjustments to our capital expenditure program as warranted.

We believe that our cash on hand, cash flow from operations and availability under our credit facility, if any, will be sufficient to meet our normal recurring operating needs, debt service obligations, and our WCBB, Hackberry, Permian Basin and Grizzly capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling programs, pursue acquisitions or accelerate our Canadian oil sands project, we may be required to obtain additional funds which we may do so through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. 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 make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, 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 $1.73 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in December 2005. On December 31, 2009, the West Texas Intermediate posted price for crude oil was $79.39 per bbl and the Henry Hub spot market price of natural gas was $5.83 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.

To mitigate the effects of commodity price fluctuations, during 2009, we were party to forward sales contracts for the sale of 825,000 barrels of WCBB production at a weighted average price of $55.01 per barrel before transportation costs. We delivered approximately 49% of our 2009 production under these agreements. Initially, for the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We also entered into 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, for the period September 2009 to December 2009. In 2009, we terminated forward sales contracts for the months of March and May 2009 for an aggregate of approximately $2.0 million. For the period January 2010 through February 2010 we entered into 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. For the period March 2010 through December 2010, we have entered into 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. Under these contracts, we have committed to deliver approximately 45% of our estimated 2010 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.

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 March 2009, we became entitled to access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2009, the plugging and abandonment trust totaled approximately $3,136,000. At December 31, 2009, we had plugged 273 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

	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	$52,428,000	$ 2,842,000	$49,586,000	$ —	$ —
Asset retirement obligations	10,153,000	635,000	1,668,000	815,000	7,035,000
Total	$62,581,000	$ 3,477,000	$51,254,000	$815,000	$7,035,000

(1) Does not include estimated interest of $1,921,000 less than one year, $5,220,000 1-3 years, and $3,348,000 3-5 years and short-term derivative instruments of $18,735,000 less than one year.

New Accounting Pronouncements

In June 2009, the FASB issued the FASB Accounting Standards Codification, or ASC, and the Hierarchy of Generally Accepted Accounting Principles, which we refer to as the Codification. The Codification became the single official source of authoritative, nongovernmental U.S. generally accepted accounting principles, or GAAP. The Codification did not change GAAP but reorganizes the literature. The Codification is effective for interim and annual periods ending after September 15, 2009. There was no impact to our consolidated financial statements as a result of the Codification.

Effective January 1, 2008, we implemented FASB ASC Topic 820, "Fair Value Measurements and Disclosures," or FASB ASC 820, which defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We elected to implement this statement with the permitted one-year deferral for nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed on a recurring basis. The deferral applied to nonfinancial assets and liabilities measured at fair value in a business combination, impaired properties, plants and equipment, intangible assets and goodwill, and initial recognition of asset retirement obligations and restructuring costs for which fair value is used. The adoption of the provisions of FASB ASC 820 did not have a material impact on our consolidated financial statements.

In December 2007, the FASB issued FASB ASC Topic 805, “Business Combinations,” or FASB ASC 805. FASB ASC 805 establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. FASB ASC 805 also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. FASB ASC 805 is effective for acquisitions that occur in an entity’s fiscal year that begins after December 15, 2008. The adoption did not have an immediate impact on our consolidated financial statements.

In December 2007, the FASB issued FASB ASC Topic 810, “Consolidation,” or FASB ASC 810, which requires that accounting and reporting for minority interest will be recharacterized as noncontrolling interest and classified as a component of equity. FASB ASC 810 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interest of the parent and the interests of the noncontrolling owners. FASB ASC 810 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity’s first fiscal year beginning after December 15, 2008. We adopted FASB ASC 810 as of January 1, 2009. The adoption did not have a material impact on our consolidated financial statements.

In March 2008, the FASB issued FASB ASC Topic 815, “Derivatives and Hedging,” or FASB ASC 815, which requires enhanced disclosures for derivative and hedging activities, including (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB ASC 815 and related interpretations, and (c) how derivative instruments and related hedged items affect an entity’s financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted FASB ASC 815 as of January 1, 2009. The adoption did not have a material impact on our consolidated financial statements.

In November 2008, the FASB ratified the consensus reached in FASB ASC Topic 323, “Investments-Equity Method and Joint Ventures,” or FASB ASC 323. FASB ASC 323 was issued to address questions that arose regarding the application of the equity method subsequent to the issuance of FASB ASC 805. FASB ASC 323 concluded that the equity method investments should continue to be recognized using a cost accumulation model, thus continuing to include transaction costs in the carrying amount of the equity method investment. In addition, FASB ASC 323 clarifies that an impairment assessment should be applied to the equity method investment as a whole, rather than to the individual assets underlying the investment. FASB ASC 323 is effective for fiscal years beginning on or after December 15, 2008. We adopted FASB ASC 323 as of January 1, 2009. The adoption did not have a material impact on our consolidated financial statements.

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 will 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 are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. Early adoption is not permitted in quarterly reports prior to the first annual report in which the revised disclosures are required. 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 21 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 is 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 are 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 August 2009, the FASB issued FASB ASC Topic 820, "Fair Value Measurements and Disclosures," or FASB ASC 820, in order to clarify how entities should estimate the fair value of liabilities. FASB ASC 820 clarifies that in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more of the prescribed valuation techniques. We adopted the guidance effective October 1, 2009. The adoption did not have a material impact on our consolidated financial statements.

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, 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 $1.73 per million British thermal units, or MMBtu, in September 2009 to a high of $15.52 per MMBtu in December 2005. On December 31, 2009, the West Texas Intermediate posted price for crude oil was $79.39 per bbl and the Henry Hub spot market price of natural gas was $5.83 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.

To mitigate the effects of commodity price fluctuations, during 2009, we were party to forward sales contracts for the sale of 825,000 barrels of WCBB production at a weighted average price of $55.01 per barrel before transportation costs. We delivered approximately 49% of our 2009 production under these agreements. Initially, for the period January through December 2009, we had entered into agreements to sell 3,000 barrels of WCBB production per day at a weighted average daily price of $89.06 per barrel before transportation costs. In December 2008, we terminated these 2009 forward sales contracts in exchange for $39.0 million in cash. Subsequently, we entered into forward sales contracts for the sale of 3,000 barrels of WCBB production per day at a weighted average daily price of $55.17 per barrel, before transportation costs, for the period April 2009 to August 2009. We also entered into 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, for the period September 2009 to December 2009. In 2009, we terminated forward sales contracts for the months of March and May 2009 for an aggregate of approximately $2.0 million. For the period January 2010 through February 2010 we entered into 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. For the period March 2010 through December 2010, we have entered into 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. Under these contracts, we have committed to deliver approximately 45% of our estimated 2010 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.

Our credit facility and term loans with Bank of America are structured under floating rate terms and, as such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. Borrowings under our revolving credit facility with Bank of America under the restated credit agreement bear interest at the Eurodollar rate plus 3.5% (3.73% at December 31, 2009). Outstanding borrowings under the term loan under the restated credit agreement accrue interest at the Eurodollar Rate (as defined in the credit agreement) plus 4% (4.23% at December 31, 2009) or, at our option, at the base rate (which is the highest of the lender's prime rate, the Federal funds rate plus 1/2 of 1%, and the one-month Eurodollar Rate plus 1%) plus 3%. Borrowings under our other term loan with Bank of America bear interest at Bank of America prime (3.25% at December 31, 2009). Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $584,000 per year, based on an aggregate of $49.9 million outstanding under our credit facilities as of December 31, 2009. As of December 31, 2009, 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, 2009, 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, 2009, 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.

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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 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, 2009.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2009 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2009, 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

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, 2009, 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, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We have also 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, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2009 and our report dated March 12, 2010 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 12, 2010

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).

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Exhibit Number	Description
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	Amended and Restated Credit Agreement, dated as of December 31, 2009, among the Company, each lender from time to time party thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 6, 2010).
10.6	Continuing Guaranty, dated as of December 31, 2009, made by Grizzly Holdings, Inc., Jaguar Resources LLC and Gator Marine, Inc. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 6, 2010).
10.7	Amended and Restated Revolving Note, dated December 31, 2009, issued by the Company under the Restated Credit Agreement (incorporated by reference to Exhibit 10.3 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 6, 2010).
10.8	Term Note, dated December 31, 2009, issued by the Company under the Restated Credit Agreement (incorporated by reference to Exhibit 10.4 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 6, 2010).
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 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 Pinnacle Energy Services, LLC.

*	Filed herewith
+	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: March 12, 2010

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: March 12, 2010	By: /s/ JAMES D. PALM **James D. Palm** **Chief Executive Officer and Director** **(Principal Executive Officer)**
Date: March 12, 2010	By: /s/ MIKE LIDDELL **Mike Liddell** **Chairman of the Board and Director**
Date: March 12, 2010	By: /s/ MICHAEL G. MOORE **Michael G. Moore** **Vice President and Chief Financial Officer** **(Principal Financial and Accounting Officer)**
Date: March 12, 2010	By: /s/ DONALD DILLINGHAM **Donald Dillingham** **Director**
Date: March 12, 2010	By: /s/ DAVID L. HOUSTON **David L. Houston** **Director**
Date: March 12, 2010	By: /s/ SCOTT E. STRELLER **Scott E. Streller** **Director**

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation:

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gulfport Energy Corporation and Subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1, the Company changed its method of estimating oil and gas reserves and related disclosures in 2009.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Gulfport Energy Corporation and Subsidiaries' internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 12, 2010 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 12, 2010

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GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(Amounts rounded to nearest thousand)

	December 31, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 1,724,000	$ 5,944,000
Accounts receivable—oil and gas	9,492,000	12,543,000
Accounts receivable—related parties	136,000	1,101,000
Prepaid expenses and other current assets	2,047,000	1,045,000
Total current assets	13,399,000	20,633,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $17,521,000 and $22,543,000 excluded from amortization in 2009 and 2008, respectively	628,849,000	599,761,000
Other property and equipment	7,182,000	7,168,000
Accumulated depletion, depreciation, amortization and impairment	(473,915,000)	(444,690,000)
Property and equipment, net	162,116,000	162,239,000
Other assets:		
Equity investments	32,006,000	25,440,000
Note receivable—related party	15,920,000	9,153,000
Other assets	3,370,000	3,755,000
Total other assets	51,296,000	38,348,000
Deferred tax asset	533,000	653,000
Total assets	$ 227,344,000	$ 221,873,000
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 20,977,000	$ 27,772,000
Asset retirement obligation—current	635,000	635,000
Short-term derivative instruments	18,735,000	—
Current maturities of long-term debt	2,842,000	815,000
Total current liabilities	43,189,000	29,222,000
Asset retirement obligation—long-term	9,518,000	8,634,000
Long-term debt, net of current maturities	49,586,000	69,916,000
Total liabilities	102,293,000	107,772,000
Commitments and contingencies (Notes 18 and 19)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding	—	—
Stockholders' equity:		
Common stock—$.01 par value, 100,000,000 authorized, 42,696,409 issued and outstanding in 2009 and 42,639,201 in 2008	427,000	426,000
Paid-in capital	273,901,000	273,343,000
Accumulated other comprehensive income (loss)	(18,039,000)	(4,803,000)
Retained earnings (accumulated deficit)	(131,238,000)	(154,865,000)
Total stockholders' equity	125,051,000	114,101,000
Total liabilities and stockholders' equity	$ 227,344,000	$ 221,873,000

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts rounded to nearest thousand)

	Year Ended December 31,		
	2009	2008	2007
Revenues:			
Oil and condensate sales	$81,587,000	$ 131,825,000	$100,120,000
Gas sales	1,992,000	6,570,000	6,043,000
Natural gas liquid sales	1,997,000	3,255,000	—
Other income (expense)	(314,000)	(433,000)	(325,000)
	85,262,000	141,217,000	105,838,000
Costs and expenses:			
Lease operating expenses	16,316,000	22,856,000	16,670,000
Production taxes	9,797,000	15,813,000	12,667,000
Depreciation, depletion, and amortization	29,225,000	42,472,000	29,681,000
Impairment of oil and gas properties	—	272,722,000	—
General and administrative	4,992,000	6,843,000	5,802,000
Accretion expense	582,000	560,000	554,000
	60,912,000	361,266,000	65,374,000
INCOME (LOSS) FROM OPERATIONS	24,350,000	(220,049,000)	40,464,000
OTHER (INCOME) EXPENSE:			
Interest expense	2,309,000	4,762,000	3,091,000
Settlement of fixed price contracts	—	(39,000,000)	—
Insurance proceeds	(1,050,000)	(769,000)	—
Interest income	(564,000)	(540,000)	(523,000)
	695,000	(35,547,000)	2,568,000
INCOME (LOSS) BEFORE INCOME TAXES	23,655,000	(184,502,000)	37,896,000
INCOME TAX EXPENSE	28,000	—	121,000
NET INCOME (LOSS)	$23,627,000	$(184,502,000)	$ 37,775,000
NET INCOME (LOSS) PER COMMON SHARE:			
Basic	$ 0.55	$ (4.33)	$ 1.03
Diluted	$ 0.55	$ (4.33)	$ 1.01

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(Amounts rounded to nearest thousand except shares)

	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount				
Balance at January 1, 2007	33,659,759	337,000	131,610,000	—	(8,138,000)	123,809,000
Net income	—	—	—	—	37,775,000	37,775,000
Other Comprehensive Income:						
Foreign currency translation adjustment	—	—	—	2,254,000	—	2,254,000
Total Comprehensive Income						40,029,000
Stock Compensation	—	—	1,158,000	—	—	1,158,000
Issuance of Common Stock in public offerings, net of related expenses of $740,000	8,547,500	85,000	138,173,000	—	—	138,258,000
Issuance of Restricted Stock	35,930	—	—	—	—	—
Issuance of Common Stock through exercise of options	210,398	2,000	866,000	—	—	868,000
Balance at December 31, 2007	42,453,587	424,000	271,807,000	2,254,000	29,637,000	304,122,000
Net loss	—	—	—	—	(184,502,000)	(184,502,000)
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment	—	—	—	(7,057,000)	—	(7,057,000)
Total Comprehensive Income (Loss)						(191,559,000)
Stock Compensation	—	—	1,056,000	—	—	1,056,000
Issuance of Restricted Stock	41,493	—	—	—	—	—
Issuance of Common Stock through exercise of options	144,121	2,000	480,000	—	—	482,000
Balance at December 31, 2008	42,639,201	426,000	273,343,000	(4,803,000)	(154,865,000)	114,101,000
Net income	—	—	—	—	23,627,000	23,627,000
Other Comprehensive Income (Loss):						
Foreign currency translation adjustment	—	—	—	5,499,000	—	5,499,000
Change in fair value of derivative instruments	—	—	—	(13,422,000)	—	(13,422,000)
Reclassification of derivative contracts	—	—	—	(5,313,000)	—	(5,313,000)
Total Comprehensive Income (Loss)						10,391,000
Stock Compensation	—	—	529,000	—	—	529,000
Issuance of Restricted Stock	43,458	—	—	—	—	—
Issuance of Common Stock through exercise of options	13,750	1,000	29,000	—	—	30,000
Balance at December 31, 2009	42,696,409	$427,000	$273,901,000	$(18,039,000)	$(131,238,000)	$ 125,051,000

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts rounded to nearest thousand)

	Year Ended December 31,		
	2009	2008	2007
Cash flows from operating activities:			
Net income (loss)	$ 23,627,000	$(184,502,000)	$ 37,775,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Accretion of discount—Asset Retirement Obligation	582,000	560,000	554,000
Depletion, depreciation and amortization	29,225,000	42,472,000	29,681,000
Impairment of oil and gas properties	—	272,722,000	—
Stock-based compensation expense	317,000	634,000	845,000
Loss from equity investments	706,000	656,000	477,000
Interest income—note receivable	(547,000)	(410,000)	—
Deferred income tax benefit	120,000	(653,000)	—
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable	3,051,000	(2,033,000)	(2,925,000)
Decrease in accounts receivable—related party	965,000	1,107,000	1,994,000
(Increase) decrease in prepaid expenses	(1,002,000)	301,000	(374,000)
(Decrease) increase in accounts payable and accrued liabilities	(3,686,000)	5,328,000	2,153,000
Settlement of asset retirement obligation	(59,000)	(859,000)	(1,278,000)
Net cash provided by operating activities	53,299,000	135,323,000	68,902,000
Cash flows from investing activities:			
Deductions (additions) to cash held in escrow	8,000	(40,000)	(121,000)
Additions to deposits for oil and gas properties	—	—	(3,080,000)
Additions to other property, plant and equipment	(14,000)	(60,000)	(457,000)
Additions to oil and gas properties	(49,533,000)	(126,030,000)	(220,044,000)
Proceeds from sale of oil and gas properties	18,286,000	—	500,000
Note receivable—related party	(4,377,000)	(10,519,000)	—
Investment in Grizzly Oil Sands ULC	—	(151,000)	(17,316,000)
Investment in Tatex Thailand II, LLC	197,000	862,000	(88,000)
Investment in Tatex Thailand III, LLC	(3,813,000)	(885,000)	—
Investment in Windsor Bakken, LLC	—	—	(127,000)
Net cash used in investing activities	(39,246,000)	(136,823,000)	(240,733,000)
Cash flows from financing activities:			
Principal payments on borrowings	(18,303,000)	(25,802,000)	(47,158,000)
Borrowings on line of credit	—	30,000,000	76,000,000
Proceeds from issuance of common stock, net of offering costs of $740,000 for 2007, and exercise of stock options	30,000	482,000	139,126,000
Net cash (used in) provided by financing activities	(18,273,000)	4,680,000	167,968,000
Net (decrease) increase in cash and cash equivalents	(4,220,000)	3,180,000	(3,863,000)
Cash and cash equivalents at beginning of period	5,944,000	2,764,000	6,627,000
Cash and cash equivalents at end of period	$ 1,724,000	$ 5,944,000	$ 2,764,000
Supplemental disclosure of cash flow information:			
Interest payments	$ 2,300,000	$ 4,898,000	$ 3,341,000
Income tax payments	$ 543,000	$ 135,000	$ 121,000
Supplemental disclosure of non-cash transactions:			
Investment subscription payable	$ —	$ —	$ 151,000
Capitalized stock based compensation	$ 212,000	$ 422,000	$ 313,000
Asset retirement obligation capitalized	$ 361,000	$ 934,000	$ 500,000
Dissolution of interest in Windsor Bakken, LLC	$ —	$ 2,468,000	$ —
Foreign currency translation gain (loss) on investment in Grizzly Oil Sands ULC	$ 3,656,000	$ (5,281,000)	$ 2,254,000
Foreign currency translation gain (loss) on note receivable—related party	$ 1,843,000	$ (1,776,000)	$ —

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2009, 2008 AND 2007
(Amounts rounded to nearest thousand)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation ("Gulfport" or the "Company") is an independent oil and gas exploration, development and production company with its principal properties located in the Louisiana Gulf Coast and in West Texas in the Permian Basin and has investments in companies operating in Canada and Thailand.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the statement of cash flows.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly owned subsidiaries, Grizzly Holdings Inc., Jaguar Resources LLC, Gator Marine, Inc. and Puma Resources, Inc. All intercompany balances and transactions are eliminated in consolidation.

Accounts Receivable

The Company's accounts receivable—oil and gas primarily are from companies in the oil and gas industry. The majority of its receivables are from two purchasers of the Company's oil and gas and one operator of certain of the Company's properties. Credit is extended based on evaluation of a customer's payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2009 and December 31, 2008.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, based on the 12-month unweighted average of the first-day-of the month price for the period January through December 2009, and for prior years, year-end prices, and costs as adjusted for the Company's cash flow hedge positions and net of tax effects, discounted at 10% per year, from proven oil and 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 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 gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and gas reserves. Oil and gas properties not subject

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
DECEMBER 31, 2009, 2008 AND 2007
(Amounts rounded to nearest thousand)

to amortization consist of the cost of unproved leaseholds and totaled $17,521,000 and $22,543,000 at December 31, 2009 and December 31, 2008, respectively. These costs are reviewed quarterly by management for impairment. If an impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities under FASB ASC Topic 410, "*Asset Retirement and Environmental Obligations*" ("FASB ASC 410"), which requires the Company 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, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. 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.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over estimated useful lives of the related assets, which range from 3 to 30 years.

Foreign Currency

The U.S. dollar is the functional currency for Gulfport's consolidated operations. However, the Company has an equity investment in a Canadian entity whose functional currency is the Canadian dollar. The assets and liabilities of the Canadian investment are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders' equity. The following table presents the balances of the Company's cumulative translation adjustments included in accumulated other comprehensive income.

December 31, 2006	$ —
December 31, 2007	$ 2,254,000
December 31, 2008	$(4,803,000)
December 31, 2009	$ 696,000

Net Income per Common Share

Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net income per common share are illustrated in Note 13.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
DECEMBER 31, 2009, 2008 AND 2007
(Amounts rounded to nearest thousand)

Income Taxes

Gulfport uses 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 as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The company adopted the provisions of FASB ASC Topic 740 as of January 1, 2007. The adoption of FASB ASC 740 had no effect on the Company's consolidated financial statements. The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company's 1996 – 2008 U.S. federal and state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2009, the Company has no unrecognized tax benefits that would have a material impact on the effective rate. The Company is continuing its practice of recognizing interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. For the year ended December 31, 2009, there is no interest or penalties associated with uncertain tax positions in the Company's consolidated financial statements.

Revenue Recognition

Gas revenues are recorded in the month produced and delivered to the purchaser using the entitlement method, whereby any production volumes received in excess of the Company's ownership percentage in the property are recorded as a liability. If less than Gulfport's entitlement is received, the underproduction is recorded as a receivable. There is no such liability or asset recorded at December 31, 2009 and 2008 because the Company has no imbalances. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments—Equity Method

Investments in entities greater than 20% and less than 50% are accounted for under the equity method. Under the equity method, the Company's share of investees' earnings or loss is recognized in the statement of operations. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company recognizes an impairment provision. There was no impairment of equity method investments at December 31, 2009 or 2008.

Accounting for Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with the provisions of FASB ASC Topic 718, "*Compensation—Stock Compensation*" ("FASB ASC 718"). FASB ASC 718 requires share-based payments to employees, including grants of employee stock options, to be recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
DECEMBER 31, 2009, 2008 AND 2007
(Amounts rounded to nearest thousand)

Accounting for Derivative Instruments and Hedging Activities

The Company may seek to reduce its exposure to unfavorable changes in oil prices by utilizing energy swaps and collars, or fixed-price contracts. The Company follows the provisions of FASB ASC 815, "*Derivatives and Hedging*" ("FASB ASC 815") as amended. It requires that all derivative instruments be recognized as assets or liabilities in the statement of financial position, measured at fair value.

The Company estimates 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 the Company's realized prices, time to maturity and credit risk. The values reported in the consolidated 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. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations, the realization of deferred tax assets and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company's oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties.

Recent Accounting Pronouncements

In June 2009, the FASB issued the FASB Accounting Standards Codification ("ASC") and the Hierarchy of Generally Accepted Accounting Principles (the "Codification"). The Codification became the single official source of authoritative, nongovernmental U.S. generally accepted accounting principles ("GAAP"). The Codification did not change GAAP but reorganizes the literature. The Codification is effective for interim and annual periods ending after September 15, 2009. There was no impact on the Company's consolidated financial statements as a result of the Codification.

Effective January 1, 2007, the Company adopted FASB ASC Topic 740, "*Income Taxes*" ("FASB ASC 740"). FASB 740 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Based on this guidance, the Company regularly analyzes tax positions taken or expected to be taken in a tax return based on the threshold prescribed under FASB 740. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. The adoption of FASB ASC 740 had no effect on the Company's consolidated financial statements.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
DECEMBER 31, 2009, 2008 AND 2007
(Amounts rounded to nearest thousand)

Effective January 1, 2008, the Company implemented FASB ASC Topic 820, *"Fair Value Measurements and Disclosures"* ("FASB ASC 820"), which defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. The Company elected to implement the provisions of FASB ASC 820 with the permitted one-year deferral for nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed on a recurring basis until the effective date of January 1, 2009. The deferral applied to nonfinancial assets and liabilities measured at fair value in a business combination, impaired properties, plants and equipment, intangible assets and goodwill, and initial recognition of asset retirement obligations and restructuring costs for which fair value is used. The adoption of the provisions of FASB ASC 820 did not have a material impact on the Company's consolidated financial statements.

In December 2007, the FASB issued FASB ASC Topic 805, "*Business Combinations*" ("FASB ASC 805"). FASB ASC 805 establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. FASB ASC 805 also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. FASB ASC 805 is effective for acquisitions that occur in an entity's fiscal year that begins after December 15, 2008. The adoption did not have an immediate impact on the Company's consolidated financial statements.

In December 2007, the FASB issued FASB ASC Topic 810, "*Consolidation*" ("FASB ASC 810"), which requires that accounting and reporting for minority interest will be recharacterized as noncontrolling interest and classified as a component of equity. FASB ASC 810 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interest of the parent and the interests of the noncontrolling owners. FASB ASC 810 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008. The Company adopted FASB ASC 810 as of January 1, 2009. The adoption did not have a material impact on the Company's consolidated financial statements.

In March 2008, the FASB issued FASB ASC Topic 815, "*Derivatives and Hedging*" ("FASB ASC 815"), which requires enhanced disclosures for derivative and hedging activities, including (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB ASC 815 and related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, results of operations, and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company adopted FASB ASC 815 as of January 1, 2009. The adoption did not have a material impact on the Company's consolidated financial statements.

In November 2008, the FASB ratified the consensus reached in FASB ASC Topic 323, "*Investments-Equity Method and Joint Ventures*" ("FASB ASC 323"). FASB ASC 323 was issued to address questions that arose regarding the application of the equity method subsequent to the issuance of FASB ASC 805. FASB ASC 323 concluded that the equity method investments should continue to be recognized using a cost accumulation model, thus continuing to include transaction costs in the carrying amount of the equity method investment. In addition, FASB ASC 323 clarifies that an impairment assessment should be applied to the equity method investment as a whole, rather than to the individual assets underlying the investment. FASB ASC 323 is effective for fiscal years beginning on or after December 15, 2008. The Company adopted FASB ASC 323 as of January 1, 2009. The adoption did not have a material impact to the Company's consolidated financial statements.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
DECEMBER 31, 2009, 2008 AND 2007
(Amounts rounded to nearest thousand)

In December 2008, the Securities and Exchange Commission 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 will 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 annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The Company adopted the 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. See Item 2. Properties and Note 21 for further discussion of the impact of implementation.

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*") ("FASB ASC 932"). The purpose of the amendments in this Update is to align the oil and gas reserve estimation and disclosure requirements of FASB ASC 932 with the requirements in the Security and Exchange Commission's Final Rule, "*Modernization of Oil and Gas Reporting*." The amendments to FASB ASC 932 are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The impact of the adoption of FASB ASC 932 is noted above.

In August 2009, the FASB issued Accounting Standards Update 2009-05, "*Measuring Liabilities at Fair Value*" (currently codified in FASB ASC Topic 820, "*Fair Value Measurements and Disclosures*") ("FASB ASC 820") in order to clarify how entities should estimate the fair value of liabilities. FASB ASC 820 clarifies that in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more of the prescribed valuation techniques. The Company adopted the guidance effective October 1, 2009. The adoption did not have a material impact on the Company's consolidated financial statements.

2. ACQUISITIONS

On December 20, 2007, Gulfport closed on the acquisition of an ownership interest in certain oil and gas properties located in the Permian Basin of West Texas, consisting of approximately 4,100 net acres with 32 gross producing wells from ExL Petroleum, LP and 12 other sellers. The effective date of the acquisition was November 1, 2007. The total purchase price for the assets, as adjusted at the original closing on December 20, 2007, was $85.2 million, which was recorded as oil and natural gas properties on the accompanying balance sheet. This amount includes an adjustment for the results of operations of the assets between the November 1, 2007 effective date and the December 20, 2007 closing date. The final post closing adjustments occurred 90 days from the original closing date of December 20, 2007, or March 20, 2008, and the purchase price was adjusted accordingly. The total adjusted purchase price for the assets was $83.8 million.

Gulfport funded this transaction predominately through a 4.5 million common share offering, which closed on December 12, 2007. The Company received net proceeds of approximately $75.6 million from the equity offering, as discussed in Note 8. The Company funded the remainder of the purchase price from borrowings under its line of credit.

The following unaudited pro forma results for the year ended December 31, 2007 show the effect on the Company's consolidated results of operations as if the acquisition had occurred on January 1, 2007. The pro

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forma results for the period presented are the result of combining the Company's consolidated statements of operations with the revenues and direct operating expenses of the acquired properties adjusted for (1) incremental depletion, depreciation, and amortization of oil and natural gas properties associated with the acquisition, amortized on a unit-of-production basis over the remaining life of total proved reserves, as applicable, (2) incremental accretion of discount on asset retirement obligation associated with the acquired properties, (3) estimated incremental interest expenses associated with borrowings under Gulfport's revolving credit facility to fund the acquisitions, and (4) the issuance of 4.5 million shares of common stock in the offering at January 1, 2007 rather than December 12, 2007. The pro forma information is based upon numerous assumptions, and is not necessarily indicative of what the Company's actual results would have been or the Company's future results of operations.

	Unaudited Year Ended December 31, 2007
Total revenue	$ 121,903,000
Net income	46,799,000
Net income per common share:	
Basic	$ 1.14
Diluted	$ 1.12

3. ACCOUNTS RECEIVABLE—RELATED PARTIES

Included in the accompanying December 31, 2009 and December 31, 2008 consolidated balance sheets are amounts receivable from related parties of the Company. These receivables represent amounts billed by the Company for general and administrative functions, such as accounting, human resources, legal, and technical support, performed by Gulfport's personnel on behalf of these related parties. These services are solely administrative in nature and for entities in which the Company has no property interests. The amounts reimbursed to the Company for these services are for the purpose of Gulfport recovering costs associated with the services and do not include the assessment of any fees or other amounts beyond the estimated costs of performing such services. At December 31, 2009 and December 31, 2008, these receivables totaled $136,000 and $1,101,000, respectively. The Company recorded $593,000, $1,363,000 and $11,153,000 for the years ended December 31, 2009, 2008 and 2007, respectively, for general and administrative functions which are reflected as a reduction of general and administrative expenses in the consolidated statements of operations and include the amounts under service contracts discussed below.

The Company is or has been a party to administrative service agreements with Caliber Development Company, LLC, Great White Energy Services LLC, and Diamondback Energy Services LLC. Under these agreements, the Company's services include accounting, human resources, legal and technical support. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a three-year term, and upon expiration of that term the agreements will continue on a month-to-month basis until cancelled by either party with at least 30 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach.

The Company is also a party to administrative service agreements with Stampede Farms LLC, Grizzly Oil Sands ULC, Everest Operations Management LLC and Tatex Thailand III, LLC. Under these agreements, the

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Company's services include professional and technical support and office space. The services provided and the fees for such services can be amended by mutual agreement of the parties. Each of these administrative service agreements has a two-year term, and upon expiration of that term such agreement will continue on a month-to-month basis until cancelled by either party to such agreement with at least 60 days prior written notice. Each administrative service agreement is terminable (1) by the counterparty at any time with at least 30 days prior written notice to the Company and (2) by either party if the other party is in material breach and such breach has not been cured within 30 days of receipt of written notice of such breach.

The Company was reimbursed the following amounts by the specified entities in consideration for its administrative services for the years ended December 31, 2009, 2008 and 2007. These amounts are reflected as a reduction of general and administrative expenses in the consolidated statements of operations. Wexford Capital LP ("Wexford") controls and/or owns a greater than 10% interest in each of these entities. Affiliates of Wexford own approximately 36% of Gulfport's outstanding stock.

Agreement Effective Date	Entity	December 31, 2009	2008	2007
2/9/2005	Caliber Development Company, LLC*	$ —	$ 60,000	$1,249,000
7/22/2006	Great White Energy Services LLC	61,000	83,000	754,000
9/26/2006	Diamondback Energy Services LLC*	—	10,000	17,000
3/1/2008	Stampede Farms LLC	—	159,000	123,000
3/1/2008	Grizzly Oil Sands ULC	20,000	368,000	953,000
3/1/2008	Everest Operations Management LLC	508,000	154,000	—
3/1/2008	Tatex Thailand III, LLC	—	—	—

* Agreement was terminated effective December 10, 2008.

For the year ended December 31, 2009, the Company was also reimbursed approximately $2,000 and $1,000 by Stampede Farms LLC and Everest Operations Management LLC, respectively, and approximately $20,000 and $26,000, respectively, for the year ended December 31, 2008, for office space under the administrative service agreements, which is included in other income (expense) in the consolidated statements of operations.

Effective July 1, 2008, the Company entered into an acquisition team agreement with Everest Operations Management LLC ("Everest") to identify and evaluate potential oil and gas properties in which the Company and Everest may wish to invest. Upon a successful closing of an acquisition or divestiture, the party identifying the acquisition or divestiture is entitled to receive a fee from the other party and its affiliates, if applicable, participating in such closing. The fee is equal to 1% of the party's proportionate share of the acquisition or divestiture consideration. The agreement may be terminated by either party upon 30 days notice.

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4. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2009 and 2008 are as follows:

	December 31,	
	2009	2008
Oil and natural gas properties	$ 628,849,000	$ 599,761,000
Office furniture and fixtures	2,996,000	2,982,000
Building	3,926,000	3,926,000
Land	260,000	260,000
Total property and equipment	636,031,000	606,929,000
Accumulated depletion, depreciation, amortization and impairment	(473,915,000)	(444,690,000)
Property and equipment, net	$ 162,116,000	$ 162,239,000

At December 31, 2008, the net book value of the Company's oil and natural gas properties, less related deferred income taxes, was above the calculated ceiling as a result of reduced commodity prices at December 31, 2008. As a result, the Company was required to record an impairment of its oil and natural gas properties under the full cost method of accounting in the amount of $272.7 million for the year ended December 31, 2008. No impairment of oil and natural gas properties was required for the year ended December 31, 2009.

Included in oil and natural gas properties at December 31, 2009 and December 31, 2008 is the cumulative capitalization of $14,009,000 and $10,614,000, respectively, in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $3,395,000, $4,645,000 and $2,041,000 for the years ended December 31, 2009, 2008 and 2007, respectively.

The following is a summary of Gulfport's oil and gas properties not subject to amortization as of December 31, 2009:

	Costs Incurred in				
	2009	2008	2007	Prior to 2007	Total
Acquisition costs	$2,592,000	$ 5,000	$ 13,003,000	$592,000	$ 16,192,000
Exploration costs	155,000	1,069,000	105,000	—	1,329,000
Development costs	—	—	—	—	—
Total oil and gas properties not subject to amortization	$2,747,000	$1,074,000	$ 13,108,000	$592,000	$ 17,521,000

At December 31, 2009, approximately $2,329,000 of oil and gas properties related to the Company's Belize properties is excluded from amortization as it relates to non-producing properties. In addition, approximately

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$13,842,000 of non-producing leasehold costs resulting from the Company's acquisition of West Texas Permian properties and $361,000 of non-producing leasehold costs related to the Company's Bakken properties are excluded from amortization at December 31, 2009. Approximately $989,000 of non-producing leasehold costs related to the Company's Southern Louisiana assets was also excluded from amortization. At December 31, 2008, approximately $22,543,000 of non-producing leasehold costs was not subject to amortization.

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company's activities, the inclusion of most of the above referenced costs into the Company's amortization calculation is expected to occur within three to five years.

A reconciliation of the asset retirement obligation for the years ended December 31, 2009 and 2008 is as follows:

	December 31,	
	2009	2008
Asset retirement obligation, beginning of period	$ 9,269,000	$8,634,000
Liabilities incurred	361,000	934,000
Liabilities settled	(59,000)	(859,000)
Accretion expense	582,000	560,000
Asset retirement obligation as of end of period	10,153,000	9,269,000
Less current portion	635,000	635,000
Asset retirement obligation, long-term	$ 9,518,000	$8,634,000

5. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2009 and 2008:

	December 31,	
	2009	2008
Investment in Tatex Thailand II, LLC	$ 2,485,000	$ 2,683,000
Investment in Tatex Thailand III, LLC	4,482,000	876,000
Investment in Grizzly Oil Sands ULC	25,039,000	21,881,000
	$ 32,006,000	$ 25,440,000

Tatex Thailand II, LLC

During 2005, the Company purchased a 23.5% ownership interest in Tatex Thailand II, LLC ("Tatex") at a cost of $2,400,000. The remaining interests in Tatex are owned by entities controlled by Wexford. Tatex, a non-public entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC ("APICO"), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering three million acres which includes the Phu Horm Field. During 2009, Gulfport paid $320,000 in cash calls and received $517,000 in distributions, bringing its total investment in Tatex (including previous investments) to $2,485,000. The loss on equity investment related to Tatex was immaterial for the years ended December 31, 2009, 2008 and 2007.

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Tatex Thailand III, LLC

During the first quarter of 2008, the Company purchased a 5% ownership interest in Tatex Thailand III, LLC ("Tatex III") at a cost of $850,000. In December 2009, the Company purchased an additional approximately 12.9% ownership interest at a cost of approximately $3,385,000 bringing its total ownership interest to approximately 17.9%. Approximately 68.7% of the remaining interests in Tatex III are owned by entities controlled by Wexford. During the year ended December 31, 2009, Gulfport paid $428,000 in cash calls, bringing its total investment in Tatex III to $4,482,000. The Company recognized a loss on equity investment of $207,000 and $9,000 for the year ended December 31, 2009 and 2008, respectively, which is included in other income (expense) in the consolidated statements of operations.

Windsor Bakken, LLC

During 2005, the Company purchased a 20% ownership interest in Windsor Bakken, LLC ("Bakken"). The remaining interests in Bakken are owned by entities controlled by Wexford. Beginning in 2005, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern Montana. As of December 31, 2007, Gulfport's net investment in Bakken was $2,468,000. As of December 31, 2007, Bakken had commenced drilling of some of its undeveloped acreage. The Company recognized losses on equity investment of $92,000 for the year ended December 31, 2007 which is included in other income (expense) in the consolidated statements of operations.

Effective January 1, 2008, the Company acquired a direct, undivided 20% interest in Bakken's assets in redemption of its 20% interest in Bakken. As a result, the Company recognized $2,468,000 of oil and natural gas assets which was included in oil and natural gas properties on the accompanying consolidated balance sheets.

Grizzly Oil Sands ULC

During the third quarter of 2006, the Company, through its wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oil Sands ULC ("Grizzly"), a Canadian unlimited liability company, for approximately $8.2 million. The remaining interests in Grizzly are owned by entities controlled by Wexford. During 2006 and 2007, Grizzly acquired leases in the Athabasca region located in the Alberta Province near Fort McMurray near other oil sands development projects. Grizzly has commenced drilling of core holes for feasibility of oil production in five separate lease blocks but has not commenced development of operations. As of December 31, 2009 and 2008, Gulfport's net investment in Grizzly was $25,039,000 and $21,881,000, respectively. Grizzly's functional currency is the Canadian dollar. The Company's investment in Grizzly was increased by $3,656,000 as a result of a currency translation gain for the year ended December 31, 2009 and decreased by $5,281,000 as a result of a currency translation loss for the year ended December 31, 2008. The Company recognized a loss on equity investment of $498,000, $639,000 and $385,000 for the years ended December 31, 2009, 2008 and 2007, respectively, which is included in other income (expense) in the consolidated statements of operations.

The Company, through its wholly owned subsidiary Grizzly Holdings Inc., entered into a loan agreement with Grizzly effective January 1, 2008, under which Grizzly may borrow funds from the Company. Borrowed funds bear interest at LIBOR plus 400 basis points. Interest is paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The loan matures on December 31, 2012. The Company loaned Grizzly approximately $4,377,000 during the year ended December 31, 2009. The Company recognized interest income of approximately $547,000 and $410,000 for the years ended December 31, 2009 and 2008, respectively, which

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is included in interest income in the consolidated statements of operations. The note balance was increased by approximately $1,843,000 as a result of a currency translation gain for the year ended December 31, 2009 and decreased by approximately $1,776,000 as a result of a currency translation loss for the year ended December 31, 2008. The total $15,920,000 due from Grizzly is included in note receivable—related party on the accompanying consolidated balance sheets.

The table below summarizes financial information for Grizzly as of December 31, 2009, 2008 and 2007.

	December 31,		
	2009	2008	2007
Current assets	$ 2,064,000	$ 1,481,000	$ 428,000
Noncurrent assets	$ 164,043,000	$ 125,024,000	$ 114,857,000
Current liabilities	$ 1,585,000	$ 2,663,000	$ 4,175,000
Noncurrent liabilities	$ 64,365,000	$ 36,397,000	$ —
Gross revenue	$ —	$ —	$ —
Loss from continuing operations	$ 1,992,000	$ 2,595,000	$ 1,540,000
Net loss	$ 1,991,000	$ 2,557,000	$ 1,540,000

6. OTHER ASSETS

Other assets consist of the following as of December 31, 2009 and 2008:

	December 31,	
	2009	2008
Plugging and abandonment escrow account on the WCBB properties (Note 18)	$ 3,136,000	$ 3,144,000
Certificates of Deposit securing letter of credit	200,000	200,000
Prepaid drilling costs	30,000	407,000
Deposits	4,000	4,000
	$ 3,370,000	$ 3,755,000

7. LONG-TERM DEBT

A break-down of long-term debt as of December 31, 2009 and 2008 is as follows:

	December 31,	
	2009	2008
Reducing credit agreement (1)	$45,000,000	$64,521,000
Term loans (1)	4,903,000	3,588,000
Building loans (2)	2,525,000	2,622,000
Less: current maturities of long term debt	(2,842,000)	(815,000)
Debt reflected as long term	$49,586,000	$69,916,000

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Maturities of long-term debt as of December 31, 2009 are as follows:

2010	$ 2,842,000
2011	48,132,000
2012	714,000
2013	740,000
2014	—
Thereafter	—
Total	$ 52,428,000

(1) On March 11, 2005, Gulfport entered into a three-year secured reducing credit agreement, as amended, with Bank of America, N.A. providing for a revolving credit facility. Borrowings under the revolving credit facility are subject to a borrowing base limitation, which was initially set at $18.0 million, subject to adjustment. On November 1, 2005, the amount available under the borrowing base limitation was increased to $23.0 million and was redetermined without change on May 30, 2006. On December 19, 2006, the amount available under the borrowing base limitation was increased to $30.0 million. Effective July 19, 2007, the credit facility was increased to $150.0 million and the amount available under the borrowing base limitation was increased to $60.0 million. In connection with the Company's acquisition of strategic assets in West Texas in the Permian Basin, effective as of December 20, 2007, the borrowing base under the revolving credit facility was increased from $60.0 million to $90.0 million. In addition, the maturity date was extended from March 31, 2009 to March 31, 2010. On August 31, 2009, the lender completed its periodic redetermination of the Company's borrowing base giving consideration to year-end 2008 and mid-year 2009 reserve information and then current bank pricing decks, among other factors. As a result of this redetermination, the Company's available borrowing base was reset at $45.0 million, primarily in response to significant declines in commodity prices. The Company's outstanding principal balance at the effective time of this redetermination was approximately $59.0 million. Amounts borrowed under the credit facility bear interest at the Eurodollar rate plus 3.50% (3.73% at December 31, 2009). The approximately $14.0 million of outstanding borrowings under the credit facility in excess of the new borrowing base was converted into a term loan as of August 31, 2009. An initial $2.0 million payment was made on the term loan at that time and the Company agreed to make additional monthly payments of $1.0 million commencing on September 30, 2009, with all unpaid amounts due on March 31, 2010.

Outstanding borrowings under the term loan accrue interest at the Eurodollar rate (as defined in the credit agreement) plus 4.0% (4.23% at December 31, 2009) or, at the option of the Company, at the base rate (which is the highest of the lender's prime rate, the Federal funds rate plus half of 1%, and the one-month Eurodollar rate plus 1%) plus 3%. Effective August 31, 2009, the Company also agreed to an adjustment in the commitment fees, interest rates for revolving loans and fees for letters of credit under the credit facility. Specifically, the Company agreed to pay (a) commitment fees ranging from 0.5% to 0.625% (an increase from 0.15% to 0.25%), (b) margin interest rates ranging from 2.75% to 3.50% for Eurodollar loans (an increase from 1.25% to 2.0%), (c) margin interest rates ranging from 1.75% to 2.5% for base rate loans (an increase from 1.25% to 2.0%), and (d) letter of credit fees at the margin interest rates for Eurodollar loans, in each case based on the Company's utilization percentage. In addition, the Company agreed to limitations on certain dispositions and investments and to mandatory prepayments of the loans from the net cash proceeds of specified asset sales and other events.

Effective December 31, 2009, the Company entered into the amended and restated credit agreement with Bank of America, N.A., as administrative agent, and the other lenders from time to time party thereto. The restated credit agreement amended and restated the Company's original 2005 credit agreement primarily to reflect the subsequent

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amendments thereto and to extend the maturity date of the revolving loan under the original 2005 credit agreement with Bank of America, N.A. from March 31, 2010 to April 1, 2011. The restated credit agreement did not alter the March 31, 2010 maturity date of the term loan outstanding under the original 2005 credit agreement. The obligations under the restated credit agreement are guaranteed by the Company's subsidiaries.

The Company's obligations under the credit facility are collateralized by a lien on substantially all of the Company's Louisiana and West Texas assets. The restated credit agreement contains certain affirmative and negative covenants, including, but not limited to the following financial covenants: (a) the ratio of funded debt to EBITDAX (net income before deductions for taxes, excluding unrealized gains and losses related to trading securities and commodity hedges, plus depreciation, depletion, amortization and interest expense, plus exploration costs deducted in determining net income under full cost accounting) for a twelve-month period may not be greater than 2.00 to 1.00; and (b) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. The Company was in compliance with all covenants at December 31, 2009. As it has historically, the Company continues to make all interest payments on time.

As of December 31, 2009, approximately $45.0 million was outstanding under the revolving credit facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet and approximately $2.0 million was outstanding under this term loan, which is included in current maturities of long-term debt on the accompanying consolidated balance sheet.

On July 10, 2006, Gulfport entered into a $5 million term loan agreement with Bank of America, N.A. related to the purchase of new gas compressor units. The loan began amortizing quarterly on March 31, 2007 on a straight-line basis over seven years based on the outstanding principal balance at December 31, 2006. The Company makes quarterly principal payments of approximately $176,000. Amounts borrowed bear interest at Bank of America Prime (3.25% at December 31, 2009). The Company makes quarterly interest payments on amounts borrowed under the agreement. The Company's obligations under the agreement are collateralized by a lien on the compressor units. As of December 31, 2009, approximately $2.9 million was outstanding under this agreement, of which $714,000 and $2.2 million are included in current maturities of long-term debt and long-term debt, net of current maturities, respectively, on the accompanying consolidated balance sheet.

(2) In June 2004, the Company purchased the office building it occupies 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 the other loan matures in June 2011 and bears interest at the rate of 6.5% per annum. In addition, the building loans included a loan related to a building in Lafayette, Louisiana, purchased in 1996 to be used as the Company's Louisiana headquarters. This loan bore interest at the rate of 5.75% per annum. The Company paid this loan in full during the third quarter of 2007, in advance of its February 2008 maturity date. The remaining building loan requires monthly interest and principal payments of approximately $23,000 and is collateralized by the Oklahoma City office building and associated land**.**

8. COMMON STOCK OPTIONS, RESTRICTED STOCK, WARRANTS AND CHANGES IN CAPITALIZATION

Options

The Company sponsors the 1999 Stock Option Plan (the "Plan"), which is administered by the Compensation Committee (the "Committee") of the Board of Directors of the Company. Under the terms of the Plan, the Committee could determine: to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting period of such options and the exercisable period of such options. Eligible participants are defined as all directors of the Company, all officers of the Company and all key employees of the Company with a customary work week of at least 40 hours in the employ of the Company. The maximum number of shares for which options could be granted under the Plan, as adjusted for changes in capitalization which have taken place since the Plan's adoption, was 883,000. The Company has granted 627,337 options for the purchase of shares of the Company's common stock under the Plan as of December 31, 2009. No additional securities will be issued under the Plan other than upon exercise of options that are outstanding.

The Company replaced the Plan in January 2005 with the 2005 Stock Incentive Plan ("2005 Plan"), which is administered by the Committee. Under the terms of the 2005 Plan, the Committee may determine when options shall be granted, to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting periods of such options and the exercisable period of such options. Eligible participants are defined as employees, consultants, and directors of the Company.

On April 20, 2006, the Company amended and restated the 2005 Plan to (i) include (a) Incentive Stock Options, (b) Nonstatutory Stock Options, (c) Restricted Awards (Restricted Stock and Restricted Stock Units), (d) Performance Awards and (e) Stock Appreciation Rights and (ii) increase the maximum aggregate amount of common stock that may be issued under the 2005 Plan from 1,904,606 shares to 3,000,000 shares, including the 627,337 shares underlying options granted to employees under the Plan prior to adoption of the 2005 Plan. As of December 31, 2009, the Company has granted 997,269 options for the purchase of shares of the Company's common stock under the 2005 Plan.

Restricted Stock

On April 1, 2007, the Company granted 16,389 shares of restricted common stock of the Company. These shares vest monthly over a three year period. On May 15, 2007, the Company granted 10,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period. On August 14, 2007, the Company granted 8,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period. On November 9, 2007, the Company granted 3,000 shares of restricted common stock of the Company. These shares vest in equal monthly installments over a three year period.

On March 13, 2008, the Company granted 6,666 shares of restricted common stock of the Company, of which 740 shares vested on April 1, 2008 with the remaining shares vesting over 36 equal monthly installments beginning on May 1, 2008. On August 6, 2008, the Company granted 2,000 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on September 17, 2008. On September 15, 2008, the Company granted 10,000 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on September 17, 2008. On December 5, 2008, the Company granted 66,667 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on December 17, 2008.

On November 3, 2009, the Company granted 13,332 shares of restricted common stock of the Company. The shares vest over twelve equal quarterly installments beginning on December 17, 2009. All shares of restricted common stock of the Company were granted under the amended and restated 2005 Plan.

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Sale of Common Stock

On January 30, 2007, the Company sold 1,150,000 shares of common stock in an underwritten offering at an offering price to the public of $11.92 per share. In connection with the offering, the Company granted the underwriter an option to purchase up to an additional 172,500 shares of common stock to cover any over-allotments, which the underwriter exercised in full on February 1, 2007. The Company received the net proceeds of approximately $15.3 million from the sale of these shares on February 5, 2007 after deducting the underwriting discount and before offering expenses.

In May 2007, the Company sold 1,500,000 shares of common stock in an underwritten offering at an offering price to the public of $16.00 per share. In connection with the offering, the Company granted the underwriter an option to purchase up to an additional 225,000 shares of common stock to cover any over-allotments, which the underwriter exercised in full. The Company received the net proceeds of approximately $26.8 million from the sale of these shares on May 22, 2007 after deducting the underwriting discount and before offering expenses.

In July 2007, the Company sold 1,000,000 share of common stock in an underwritten offering at an offering price to the public of $22.00 per share. The Company received the net proceeds of approximately $21.2 million from the sale of these shares on July 25, 2007 after deducting the underwriting discount and before offering expenses.

In December 2007, the Company sold 4,500,000 shares of common stock in an underwritten offering at an offering price to the public of $17.50 per share. The Company received the net proceeds of approximately $75.6 million from the sale of these shares on December 12, 2007 after deducting underwriting discounts and before offering expenses. In connection with the offering, a selling stockholder granted the underwriter an option to purchase an additional 675,000 shares of common stock to cover any over-allotments, which the underwriter exercised in full. The Company did not receive any proceeds from the sale of shares of the common stock by the selling stockholder.

Private Placement Offering

In March 2002, the Company completed a private placement offering of 10,000 units. Each unit consisted of (i) one share of Cumulative Preferred Stock, Series A, of the Company (the "Preferred") and (ii) a warrant to purchase up to 250 shares of common stock, par value $0.01 per share, of the Company (the "Warrants"). Holders of the Preferred were entitled to receive dividends at the rate of 12% of the liquidation preference per annum payable quarterly in cash or, at the option of the Company for all quarters ending on or prior to March 31, 2004, payable in whole or in part in additional shares of Preferred at the rate of 15% of the liquidation preference per annum. All Preferred shares were redeemed in 2005.

The 2,322,962 Warrants issued have a term of ten years and a current exercise price of $1.19 per share of common stock subject to adjustment. The Company granted to holders of the Warrants certain demand and piggyback registration rights with respect to shares of common stock issuable upon exercise of the Warrants. The Company considered the valuation of the Warrants and did not consider them materially significant. The Company had 60,550 Warrants outstanding at December 31, 2009 and 2008 which can be converted into 203,529 shares of common stock.

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9. STOCK-BASED COMPENSATION

During the years ended December 31, 2009, 2008 and 2007, the Company's stock-based compensation cost was $529,000, $1,056,000 and $1,158,000, respectively, of which the Company capitalized $212,000, $422,000 and $313,000, respectively, relating to its exploration and development efforts, which reduced basic and diluted earnings per share by $0.01 and $0.01 for the years ended December 31, 2009 and December 31, 2008, respectively.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. Expected volatilities are based on the historical volatility of the market price of Gulfport's common stock over a period of time ending on the grant date. Based upon historical experience of the Company, the expected term of options granted is equal to the vesting period plus one year. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of the grant. The 2005 Plan provides that all options must have an exercise price not less than the fair value of the Company's common stock on the date of the grant.

No stock options were issued during the years ended December 31, 2009, 2008 and 2007.

The Company has not declared dividends and does not intend to do so in the foreseeable future, and thus did not use a dividend yield. In each case, the actual value that will be realized, if any, depends on the future performance of the common stock and overall stock market conditions. There is no assurance that the value an optionee actually realizes will be at or near the value estimated using the Black-Scholes model.

A summary of the status of stock options and related activity for the years ended December 31, 2009, 2008 and 2007 are presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Options outstanding at December 31, 2006	967,233	$ 5.54	7.76	$ 7,782,000
Granted	—	—		
Exercised	(210,398)	4.13		2,284,000
Forfeited/expired	(82,445)	3.66		
Options outstanding at December 31, 2007	674,390	6.22	6.97	8,098,000
Granted	—	—		
Exercised	(144,121)	3.34		1,694,000
Forfeited/expired	(7,889)	6.17		
Options outstanding at December 31, 2008	522,380	7.01	6.24	$(1,599,000)
Granted	—	—		
Exercised	(13,750)	2.20		71,000
Forfeited/expired	—	—		
Options outstanding at December 31, 2009	508,630	$ 7.14	5.38	$ 2,192,000
Options exercisable at December 31, 2009	404,509	$ 8.11	5.46	$ 1,350,000

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Unrecognized compensation expense as of December 31, 2009 related to outstanding stock options and restricted shares was $377,000. The expense is expected to be recognized over a weighted average period of 1.49 years.

The following table summarizes information about the stock options outstanding at December 31, 2009:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$ 2.00	11,500	0.71	11,500
$ 3.36	232,241	5.06	128,120
$ 9.07	64,889	5.69	64,889
$11.20	200,000	5.92	200,000
	508,630		404,509

The following table summarizes restricted stock activity for the twelve months ended December 31, 2009, 2008 and 2007:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2006	69,518	$ 12.81
Granted	37,389	15.66
Vested	(35,930)	13.13
Forfeited	(11,944)	15.24
Unvested shares as of December 31, 2007	59,033	$ 13.94
Granted	85,333	$ 5.64
Vested	(41,493)	11.97
Forfeited	(9,417)	15.84
Unvested shares as of December 31, 2008	93,456	$ 7.04
Granted	13,332	$ 8.08
Vested	(43,458)	8.16
Forfeited	(3,086)	15.77
Unvested shares as of December 31, 2009	60,244	$ 6.01

10. INSURANCE PROCEEDS

In May 2008, the Company received insurance proceeds of approximately $769,000 related to damages incurred resulting from a 2006 barge accident in its WCBB field. The costs associated with repairing the field were expensed to lease operating expenses as incurred in 2006 and 2007. The Company recognized the insurance proceeds in other (income) expense in the accompanying consolidated statements of operations.

In March 2009, the Company received insurance proceeds of approximately $1,050,000 related to damages incurred in its WCBB field as a result of Hurricane Ike in 2008. The costs associated with repairing the field were

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expensed to lease operating expenses as incurred in 2008 and 2009. The Company recognized the insurance proceeds in other (income) expense in the accompanying consolidated statements of operations. In September and October 2009, the Company received additional insurance proceeds of approximately $994,000 related to damages incurred in the WCBB field as a result of Hurricane Ike and related debris removal. As the costs related to these repairs and debris removal were incurred in 2009 and expensed to lease operating expense, the Company recognized the insurance proceeds in lease operating expenses in the accompanying consolidated statements of operations.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current and long-term debt are carried at cost, which approximates market value.

The fair value of the derivative instruments is computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date, as adjusted for basis differentials. Forward market prices for oil are dependent upon supply and demand factors in such forward market and are subject to significant volatility.

12. INCOME TAXES

The income tax provision consists of the following:

	2009	2008	2007
Current:			
State	$ 28,000	$ —	$ —
Federal	32,000	653,000	121,000
Deferred:			
State	—	—	—
Federal	(32,000)	(653,000)	—
Total income tax expense (benefit) provision	$ 28,000	$ —	$121,000

A reconciliation of the statutory federal income tax amount to the recorded expense follows:

	2009	2008	2007
Income (loss) before federal income taxes	$23,655,000	$(184,502,000)	$ 37,775,000
Expected income tax at statutory rate	8,279,000	(64,576,000)	13,221,000
State income taxes	1,370,000	(7,033,000)	2,131,000
Other differences	(891,000)	(527,000)	528,000
Changes in valuation allowance	(8,730,000)	72,136,000	(15,759,000)
Income tax expense recorded	$ 28,000	$ —	$ 121,000

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The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2009, 2008 and 2007 are estimated as follows:

	2009	2008	2007
Deferred tax assets:			
Net operating loss carryforward	$ 22,268,000	$ 23,810,000	$37,197,000
Oil and gas property basis difference	49,638,000	57,789,000	—
FASB ASC 718 compensation expense	341,000	238,000	216,000
Investment in pass through entities	528,000	—	72,000
AMT credit	598,000	718,000	64,000
Non-oil and gas property basis difference	316,000	118,000	148,000
Total deferred tax assets	73,689,000	82,673,000	37,697,000
Deferred tax liabilities:			
Oil and gas property basis difference	—	—	27,947,000
Investment in pass through entities	—	134,000	—
Unrealized gain on hedging activities	—	—	—
Total deferred tax liabilities	—	134,000	27,947,000
Total deferred tax asset	73,689,000	82,539,000	9,750,000
Valuation allowance	(73,156,000)	(81,886,000)	(9,750,000)
Net deferred tax asset (liability)	$ 533,000	$ 653,000	$ —

The Company has an available tax net operating loss carryforward estimated at approximately $55,671,000 as of December 31, 2009. This carryforward will begin to expire in the year 2018. A valuation allowance has been provided at December 31, 2009, 2008 and 2007 because it is management's belief, based upon the Company's past history of no taxable income and future projections of no taxable income during the carryforward period, it is more likely than not the net deferred tax assets will not be realized.

The Company had income tax expense of $121,000 during the year ended December 31, 2007 related to the payment of alternative minimum taxes due for 2006 and 2007. Although the Company has substantial net operating loss carryforwards, these cannot be used to offset alternative minimum tax liabilities. In 2009, the Company had income tax expense of $28,000 related to state income tax.

13. EARNINGS PER SHARE

A reconciliation of the components of basic and diluted net income per common share is presented in the table below:

	2009			2008			2007		
	Income	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
Basic:									
Net income (loss)	$23,627,000	42,667,581	$0.55	$(184,502,000)	42,599,611	$(4.33)	$37,775,000	36,774,163	$1.03
Effect of dilutive securities:									
Stock options and awards	—	350,067		—	—		—	676,935	
Diluted:									
Net income	$23,627,000	43,017,648	$0.55	$(184,502,000)	42,599,611	$(4.33)	$37,775,000	37,451,098	$1.01

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For the year ended December 31, 2009, options to purchase 64,889 shares at $9.07 per share and 200,000 shares at $11.20 per share were excluded from the calculation of dilutive earnings per share because they were anti-dilutive. For the year ended December 31, 2008, all options were excluded from the calculation of dilutive earnings per share because the Company had a net loss and, therefore, the effect would have been anti-dilutive. There were no potential shares of common stock that were considered anti-dilutive for the year ended December 31, 2007.

14. HEDGING ACTIVITIES

Oil Price Hedging Activities

The Company seeks to reduce its exposure to unfavorable changes in oil prices, which are subject to significant and often volatile fluctuation, by entering into forward sales contracts. These contracts allow the Company to predict with greater certainty the effective oil prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

The Company accounts for its oil derivative instruments as cash flow hedges for accounting purposes under FASB ASC 815 and related pronouncements. All derivative contracts are marked to market each quarter end and are included in the accompanying consolidated balance sheets as derivative assets and liabilities.

At December 31, 2009, the fair value of derivative liabilities related to the forward sales contracts is as follows:

Short-term derivative instruments – liability	$ 18,735,000

All forward sales contracts have been executed in connection with the Company’s oil price hedging program. For forward sales contracts qualifying as cash flow hedges pursuant to FASB ASC 815, the realized contract price is included in oil sales in the period for which the underlying production was hedged.

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. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. The Company did not recognize into earnings any amount related to hedge ineffectiveness for the year ended December 31, 2009 as the hedges were deemed to be perfectly effective.

During the first quarter of 2009, the Company entered into forward sales contracts with the purchaser of the Company’s WCBB oil. The Company receives the fixed price amount stated in the contract for the specified volumes. At December 31, 2009, the Company had the following forward sales contracts in place:

	Daily Volume (Bbls/day)	Weighted Average Price
January – February 2010	3,000	$ 54.81
March – December 2010	2,300	$ 58.24

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In the first quarter of 2009, the Company terminated forward sales contracts for 3,000 barrels per day of March 2009 production for approximately $1.5 million and terminated forward sales contracts for 3,000 barrels per day in the second quarter of 2009 for $476,000. For the year ended December 31, 2009, approximately $2.0 million related to such terminations is included in oil and condensate sales on the accompanying consolidated statements of operations. There were no contracts in place which were accounted for as hedges at December 31, 2008.

The Company delivered approximately 49% of its 2009 production under these forward sales contracts.

15. FAIR VALUE MEASUREMENTS

The Company adopted FASB ASC 820 for all financial assets and liabilities measured at fair value on a recurring basis. The Company adopted FASB ASC 820 effective January 1, 2009 for all non-financial assets and liabilities. FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1 – Quoted prices in active markets for identical assets and liabilities.

Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 – Significant inputs to the valuation model are unobservable.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

The following table summarizes the Company’s financial and nonfinancial liabilities by FASB ASC 820 valuation level as of December 31, 2009:

	Level 1	Level 2	Level 3
Assets:			
Forward sales contracts	$ —	$ —	$ —
Liabilities:			
Forward sales contracts	$ —	$18,735,000	$ —

The estimated fair value of the Company’s forward sales contracts was based upon forward commodity prices based on quoted market prices, adjusted for differentials.

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, “*Asset Retirement and Environmental Obligations*” (“FASB ASC 410”). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 4 for further discussion of the Company’s asset retirement obligations. Asset retirement obligations incurred during the twelve months ended December 31, 2009 were approximately $361,000.

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The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current and long-term debt are carried at cost, which approximates market value.

16. OPERATING LEASES

In October 2006, the Company began leasing the Louisiana building that it owns to an unrelated party. The cost of the building totaled approximately $217,000 and accumulated depreciation amounted to approximately $90,000 as of December 31, 2009. The lease commenced on October 15, 2006 and was extended to expire on October 14, 2010, with equal monthly installments of $10,500. The future minimum lease payments to be received are as follows:

Fiscal year ending December 31, 2010	$100,000

17. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company conducts business activities with certain entities affiliated with its largest stockholder.

Windsor Energy Group, LLC (“WEG”), an entity controlled by Wexford, operates the Permian Basin wells in West Texas. At December 31, 2009 and 2008, the Company owed WEG approximately $1,631,000 and $3,724,000, respectively, related to reimbursement for services provided. Approximately $2,368,000 and $2,711,000 of services provided by WEG are included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2009 and 2008, respectively. Approximately $8,063,000 and $37,693,000 related to services performed by WEG is included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2009 and 2008, respectively.

Athena Construction LLC (“Athena”), an entity controlled by Wexford, performs services for the Company at its WCBB and Hackberry fields. At December 31, 2009 and December 31, 2008, the Company owed Athena approximately $836,000 and $759,000, respectively, related to these services. Approximately $709,000 and $1,303,000 of services provided by Athena are included in lease operating expenses in the consolidated statements of operations for the years ended December 31, 2009 and 2008, respectively. Approximately $1,286,000 and $1,783,000 related to services performed by Athena are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2009 and 2008, respectively.

Packers & Service Tools, Inc. (“Packers”), an entity controlled by Wexford, performs services for the Company at its WCBB and Hackberry fields. At December 31, 2008 the Company owed Packers approximately $465,000 related to these services. Approximately $11,000 of services provided by Packers are included in lease operating expenses in the consolidated statements of operations for the year ended December 31, 2008. Approximately $1,995,000 relating to services performed by Packers are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2008. Packers ceased to be controlled by Wexford in November 2008.

Diamondback Completions LLC (“Completions”), an entity controlled by Wexford, performed services for the Company at its WCBB and Hackberry fields. At December 31, 2008, the Company owed Completions

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approximately $24,000, related to these services. Approximately $227,000 relating to services performed by Completions are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2008. Completions ceased to be controlled by Wexford in November 2008.

Great White Towing LLC ("Towing"), an entity controlled by Wexford, performed services for the Company at its WCBB field. At December 31, 2008, the Company owed Towing approximately $222,000, related to these services. No amounts were owed to Towing at December 31, 2009. Approximately $102,000 of services performed by Towing are included in lease operating expenses in the consolidated statements of operations for the year ended December 31, 2008. Approximately $339,000 relating to services performed by Towing are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2008. No services were performed by Towing in 2009.

Great White Directional Services LLC ("Directional"), an entity controlled by Wexford, performs services for the Company at its WCBB and Hackberry fields. At December 31, 2009, the Company owed Directional approximately $699,000 related to these services. No amounts were owed to Directional at December 31, 2008. Approximately $1,064,000 relating to services performed by Directional are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2009. No services were performed by Directional in 2008.

18. COMMITMENTS

Plugging and Abandonment Funds

In connection with the acquisition in 1997 of the remaining 50% interest in the WCBB properties, the Company 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, the Company can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2009, the plugging and abandonment trust totaled approximately $3,136,000. At December 31, 2009, the Company has plugged 273 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Texaco Global Settlement

Pursuant to the terms of a global settlement between Texaco and the State of Louisiana which includes the State Lease No. 50 portion of Gulfport's East Hackberry field, Gulfport was obligated to commence drilling a well or other qualifying development operation on certain non-producing acreage in the field prior to March 1998. Because of prevailing market conditions during 1998, the Company believed it was commercially impractical to shoot seismic or commence drilling operations on the subject property. As a result, Gulfport agreed to surrender approximately 440 non-producing acres in this field to the State of Louisiana. At December 31, 2009, Gulfport was in the process of releasing these properties to the State of Louisiana.

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) and Profit Sharing plan under which eligible employees may contribute up to 15% of their total compensation through salary deferrals. Also under these plans, the Company will make a

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contribution each calendar year on behalf of each employee equal to at least 3% of his or her salary, regardless of the employee's participation in salary deferrals. During the years ended December 31, 2009, 2008 and 2007, Gulfport incurred $279,000, $651,000 and $640,000, respectively, in contributions expense related to this plan.

Employment Agreement

In May 1999, Gulfport entered into an employment agreement with its Chairman of the Board. The original term of the agreement expired on May 31, 2004, but automatically renews for successive terms of one year unless Gulfport or the Chairman elects otherwise. The employment agreement calls for an annual salary of $200,000, subject to adjustment for cost of living increases.

19. CONTINGENCIES

The Louisiana Department of Revenue ("LDR") is disputing Gulfport's severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 to 2007. The LDR maintains that Gulfport paid approximately $1,800,000 less in severance taxes under fixed price terms than the severance taxes Gulfport would have had to pay had it paid severance taxes on the oil at the contracted market rates only. Gulfport has denied any liability to the LDR for underpayment of severance taxes and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. Gulfport has maintained its 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 Gulfport seeking $2,275,729 in severance taxes, plus interest and court costs. Gulfport filed a response denying any liability to the LDR for underpayment of severance taxes and is defending itself in the lawsuit. The case is in the early stages of discovery.

Other Litigation

In November 2006, Cudd Pressure Control, Inc. ("Cudd") filed a lawsuit against Gulfport, Great White Pressure Control LLC ("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. Gulfport filed a motion for summary judgment on October 5, 2007. The court entered a final interlocutory judgment in favor of all defendants, including Gulfport, 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 Gulfport 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 February 10, 2010, Gulfport filed a motion to be dismissed from the proceeding for lack of personal jurisdiction, which motion is pending. This state court proceeding is in its initial stages.

On July 27, 2007, Robotti & Company, LLC filed a putative class action lawsuit in the Court of Chancery for the State of Delaware. The original complaint alleged a breach of fiduciary duty by Gulfport and its then

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present directors in connection with the pricing of Gulfport's 2004 rights offering. Plaintiff filed an amended complaint on January 15, 2008, and Gulfport filed a motion to dismiss in early February 2008 and filed the brief in support of such motion on April 29, 2008. The court held a hearing on October 3, 2008, ultimately deciding to allow the plaintiff to file a second amended complaint. Plaintiff filed its second amended complaint December 22, 2008, which sets forth class action and derivative claim allegations that Gulfport's then present directors breached their fiduciary duty in connection with the pricing of the 2004 rights offering. The defendants filed their motion to dismiss on January 19, 2009 and their brief in support of such motion on February 20, 2009. Briefing by the parties concluded April 6, 2009, oral arguments on the motion were heard by the court on April 22, 2009 and on January 14, 2010, the court issued an opinion granting defendants' motion to dismiss and entered an order dismissing the case with prejudice.

Due to the current early stages of the LDR and Cudd litigation, the outcome is 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 effect on the Company's financial condition or results of operations.

The Company has been named as a defendant on various other litigation matters. The ultimate resolution of these matters is not expected to have a material adverse effect on the Company's financial condition or results of operations for the periods presented in the consolidated financial statements.

Concentration of Credit Risk

Gulfport operates in the oil and gas industry principally in the state of Louisiana with sales to refineries, re-sellers such as pipeline companies, and local distribution companies. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company's results of operations in the long term.

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $250,000. At December 31, 2009, Gulfport held cash in excess of insured limits in these banks totaling $1,147,000.

During the year ended December 31, 2009, Gulfport sold approximately 92% and 7% of its oil production to Shell Trading Company ("Shell") and WEG, respectively, 100% of its natural gas liquids production to WEG, and 45%, 38%, and 16% of its natural gas production to WEG, Chevron, and Hilcorp Energy Company ("Hilcorp"), respectively. During the year ended December 31, 2008, Gulfport sold approximately 87% and 11% of its oil production to Shell and WEG, respectively, 100% of its natural gas liquids production to WEG, and 60%, 22%, and 16% of its natural gas production to Chevron, WEG, and Hilcorp, respectively. During the year ended December 31, 2007, approximately 99% of Gulfport's oil sales and 69% and 23% of Gulfport's natural gas sales were attributable to three purchasers: Shell, Chevron, and Hilcorp, respectively.

Forward Sales Contracts

The Company was a party to forward sales contracts for the sale of 3,000 barrels of production per day for the month of June 2007 at a weighted average daily price of $70.15 per barrel before transportation costs. For the period of July 2007 through December 2007, the Company entered into forward sales contracts for the sale of 3,500 barrels of production per day at a weighted average daily price of $70.29 per barrel before transportation

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costs. In addition, the Company entered into forward sales contracts for the sale of 3,500 barrels of production per day for the months of January 2008 through May 2008 at a weighted average daily price of $70.29 per barrel before transportation costs. For June 2008, the Company had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $71.69 per barrel before transportation costs. For the month of July 2008, the Company had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $85.89 per barrel before transportation costs. For August 2008, Gulfport had agreements to sell 3,500 barrels of production per day at a weighted average daily price of $86.81 per barrel before transportation costs. For the periods September 2008 through December 2008, the Company entered into forward sales contracts for the sale of 3,500 barrels of production per day at a weighted average daily price of $86.60 per barrel before transportation costs. For the period of January 2009 through December 2009, the Company entered into agreements to sell 3,000 barrels of production per day at a weighted average daily price of $89.06 per barrel before transportation costs. These contracts were originally designated as normal sales of production under FASB ASC 815, based on the Company's intent to physically deliver the production quantities under the contract terms, and exempted from the provisions of FASB ASC 815.

In December 2008, the Company terminated the 2009 forward sales contracts in exchange for $39.0 million cash, which is included in other (income) expense on the accompanying consolidated statements of operations. As a result of this cash settlement, beginning in 2009, the Company is required to account for similar contracts under the provisions of FASB ASC 815 until a reasonable period passes and the Company redevelops a past history of physical delivery under fixed price contracts without net cash settlement. See Note 14 for further discussion of the Company's 2009 forward sales contracts.

20. LITIGATION TRUST ENTITY

Pursuant to the Company's 1997 plan of reorganization, all of Gulfport's possible causes of action against third parties (with the exception of certain litigation related to recovery of marine and rig equipment assets and claims against Tri-Deck), existing as of the effective date of that plan, were transferred into a "Litigation Trust" controlled by an independent party for the benefit of most of the Company's existing unsecured creditors. The litigation related to recovery of marine and rig equipment and the Tri-Deck claims were subsequently transferred to the Litigation Trust as described below.

The Litigation Trust was funded by a $3,000,000 cash payment from the Company, which was made on the effective date of reorganization. Gulfport owns a 12% interest in the Litigation Trust with the other 88% being owned by the former general unsecured creditors of Gulfport. For financial statement reporting purposes, Gulfport has not recognized the potential value of recoveries which may ultimately be obtained, if any, as a result of the actions of the Litigation Trust, treating the entire $3,000,000 payment as a reorganization cost at the time of Gulfport's reorganization.

On January 20, 1998, Gulfport and the Litigation Trust entered into a Clarification Agreement whereby the rights to pursue various claims reserved by Gulfport under the plan of reorganization were assigned to the Litigation Trust. In connection with this agreement, the Litigation Trust agreed to reimburse the Company $100,000 for legal fees Gulfport had incurred in connection with these claims. As additional consideration for the contribution of this claim to the Litigation Trust, Gulfport is entitled to 20% to 80% of the net proceeds from these claims.

In December 2009, the Company received a final distribution from the Litigation Trust of approximately $234,000. No proceeds were received from the Litigation Trust for the years ended December 31, 2008 or 2007.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
DECEMBER 31, 2009, 2008 AND 2007
(Amounts rounded to nearest thousand)

21. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES

The following is historical revenue and cost information relating to the Company's oil and gas operations located entirely in the United States:

Capitalized Costs Related to Oil and Gas Producing Activities

	2009	2008
Proven properties	$ 610,778,000	$ 577,218,000
Unproven properties	15,192,000	20,368,000
	625,970,000	597,586,000
Accumulated depreciation, depletion, amortization and impairment reserve	(470,649,000)	(441,709,000)
Net capitalized costs	$ 155,321,000	$ 155,877,000

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2009	2008	2007
Acquisition	$ 1,885,000	$ 2,468,000	$ 85,247,000
Development of proved undeveloped properties	28,652,000	64,643,000	55,930,000
Exploratory	502,000	9,764,000	57,668,000
Recompletions	8,980,000	16,877,000	9,875,000
Capitalized asset retirement obligation	361,000	934,000	500,000
Total	$ 40,380,000	$ 94,686,000	$ 209,220,000
Equity investment in Windsor Bakken LLC	$ —	$ —	$ 2,297,000

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
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Results of Operations for Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	2009	2008	2007
Revenues	$ 85,576,000	$ 141,650,000	$106,163,000
Production costs	(26,113,000)	(38,669,000)	(29,337,000)
Impairment of oil and gas assets	—	(272,722,000)	—
Depletion	(28,939,000)	(42,194,000)	(29,220,000)
	30,524,000	(211,935,000)	47,606,000
Income tax expense			
Current	28,000	—	121,000
Deferred	—	—	—
	28,000	—	121,000
Results of operations from producing activities	$ 30,496,000	$(211,935,000)	$ 47,485,000
Depletion per barrel of oil equivalent (BOE)	$ 17.25	$ 23.92	$ 17.85
Net earnings from equity method investment in Winsor Bakken LLC	$ —	$ —	$ 20,000

Oil and Gas Reserves (Unaudited)

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2009, 2008 and 2007 and changes in proved reserves during the last three years. The 2009 reserve reports use 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, 2009, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2009. Estimates of reserves as of year-end 2008 and 2007 were prepared using constant prices and costs in accordance with previous guidelines of the SEC based on hydrocarbon prices received on a field-by-field basis as of December 31st of the applicable year. Volumes for oil are stated in thousands of barrels (MBbls) and volumes for gas are stated in millions of cubic feet (MMcf). The prices used for 2009 reserve report purposes are $57.90 per barrel and $3.87 per MMbtu, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices at December 31, 2008 and 2007 used for reserve report purposes are $41.00 per barrel and $5.71 per MMbtu and $92.50 per barrel and $6.80 per MMbtu, respectively.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
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Gulfport emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

	2009		2008		2007	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved Reserves						
Beginning of the period	21,771	22,235	25,115	24,259	19,692	20,801
Purchases in oil and gas reserves in place	1,728	1,135	77	26	5,699	5,587
Extensions and discoveries	2,614	2,874	1,315	1,965	—	—
Sales of oil and gas reserves in place	(736)	(282)	—	—	—	—
Revisions of prior reserve estimates	(6,294)	(11,139)	(3,091)	(3,303)	1,225	(1,313)
Current production	(1,595)	(491)	(1,645)	(712)	(1,501)	(816)
End of period	17,488	14,332	21,771	22,235	25,115	24,259
Proved developed reserves	6,165	4,325	7,072	7,187	7,116	6,746
Equity Investment in Windsor Bakken LLC						
Net proved developed and undeveloped reserves	—	—	—	—	77	26
Net proved developed reserves	—	—	—	—	18	8

The Company experienced downward reserve revisions in estimated proved reserves in 2009. These downward revisions were primarily the result of implementing the five-year schedule for proved undeveloped reserves from the SEC's "Modernization of Oil and Gas Reporting" Final Rule. The Company experienced downward reserve revisions in estimated proved reserves in 2008. These downward revisions were primarily a result of year end commodity prices utilized for the reserve estimate decreasing from $92.50 per barrel and $6.80 per MMbtu at December 31, 2007 to $41.00 per barrel and $5.71 per MMbtu at December 31, 2008.

Discounted Future Net Cash Flows (Unaudited)

The following tables present the estimated future cash flows, and changes therein, from Gulfport's proven oil and gas reserves as of December 31, 2009, 2008 and 2007 using an unweighted average first-of-the-month price for the period January through December 2009 for 2009 and the applicable year end price for 2008 and 2007.

GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)
DECEMBER 31, 2009, 2008 AND 2007
(Amounts rounded to nearest thousand)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

	Year ended December 31,		
	2009	2008	2007
Future cash flows	$1,005,029,000	$1,023,056,000	$2,405,458,000
Future development and abandonment costs	(209,975,000)	(299,362,000)	(326,229,000)
Future production costs	(236,003,000)	(376,176,000)	(420,646,000)
Future production taxes	(97,841,000)	(109,478,000)	(275,977,000)
Future income taxes	(50,229,000)	—	(280,538,000)
Future net cash flows	410,981,000	238,040,000	1,102,068,000
10% discount to reflect timing of cash flows	(170,207,000)	(111,800,000)	(433,773,000)
Standardized measure of discounted future net cash flows	$ 240,774,000	$ 126,240,000	$ 668,295,000
Equity investment in Windsor Bakken Standardized measure of discounted cash flows	$ —	$ —	$ 1,753,000

In order to develop its proved undeveloped reserves according to the drilling schedule used by the engineers in Gulfport's reserve report, the Company will need to spend $47,845,000, $28,015,000 and $38,678,000 during years 2010, 2011 and 2012, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

	Year ended December 31,		
	2009	2008	2007
Sales and transfers of oil and gas produced, net of production costs	$ (59,463,000)	$(102,981,000)	$ (76,826,000)
Net changes in prices, production costs, and development costs	183,426,000	(662,004,000)	246,657,000
Acquisition of oil and gas reserves in place	20,981,000	376,000	121,267,000
Extensions and discoveries	32,638,000	7,801,000	—
Revisions of previous quantity estimates, less related production costs	(77,531,000)	(13,480,000)	27,970,000
Sales of reserves in place	(13,185,000)	—	—
Accretion of discount	12,624,000	66,830,000	35,265,000
Net changes in income taxes	(22,238,000)	152,949,000	(106,145,000)
Change in production rates and other	37,282,000	8,454,000	67,459,000
Total change in standardized measure of discounted future net cash flows	$114,534,000	$(542,055,000)	$ 315,647,000

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22. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2009 and 2008:

	2009			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$17,784,000	$20,514,000	$22,071,000	$ 24,893,000
Income from operations	2,214,000	5,410,000	7,130,000	9,596,000
Income tax expense	—	28,000	—	—
Net income	2,733,000	5,078,000	6,674,000	9,142,000
Income per share:				
Basic	$ 0.06	$ 0.12	$ 0.16	$ 0.21
Diluted	$ 0.06	$ 0.12	$ 0.16	$ 0.21

	2008			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter (1)
Revenues	$31,118,000	$35,802,000	$36,731,000	$ 37,566,000
Income from operations	12,660,000	14,969,000	15,119,000	(262,797,000)
Income tax expense	—	—	20,000	(20,000)
Net income	11,506,000	14,886,000	14,107,000	(225,001,000)
Income per share:				
Basic	$ 0.27	$ 0.35	$ 0.33	$ (5.28)
Diluted	$ 0.27	$ 0.35	$ 0.33	$ (5.28)

(1) Includes $272,772,000 impairment of oil and gas properties and income of $39,000,000 from the settlement of fixed price contracts.

EXHIBIT INDEX

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).

Exhibit Number	Description
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	Amended and Restated Credit Agreement, dated as of December 31, 2009, among the Company, each lender from time to time party thereto and Bank of America, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 6, 2010).
10.6	Continuing Guaranty, dated as of December 31, 2009, made by Grizzly Holdings, Inc., Jaguar Resources LLC and Gator Marine, Inc. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 6, 2010).
10.7	Amended and Restated Revolving Note, dated December 31, 2009, issued by the Company under the Restated Credit Agreement (incorporated by reference to Exhibit 10.3 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 6, 2010).
10.8	Term Note, dated December 31, 2009, issued by the Company under the Restated Credit Agreement (incorporated by reference to Exhibit 10.4 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 6, 2010).
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 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 Pinnacle Energy Services, LLC.

* Filed herewith
\+ Management contract, compensatory plan or arrangement.

Exhibit 21

SUBSIDIARIES OF GULFPORT ENERGY CORPORATION

Name of Subsidiary	Jurisdiction of Organization
Grizzly Holdings, Inc.	Delaware
Jaguar Resources LLC	Delaware
Puma Resources, Inc.	Delaware
Gator Marine, Inc.	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 12, 2010, accompanying the consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting included in the Annual Report of Gulfport Energy Corporation on Form 10-K for the year ended December 31, 2009. We hereby consent to the incorporation by reference of said reports in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001) and on Forms S-3 (File No. 333-146988, effective November 13, 2007; File No. 333-143659, effective July 18, 2007; and File No. 333-139480, effective January 23, 2007).

/s/ GRANT THORNTON LLP

Oklahoma City, OK
March 12, 2010

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF NETHERLAND, SEWELL & ASSOCIATES, INC.

We hereby consent to the inclusion in the Form 10-K of Gulfport Energy Corporation for 2009 ("Form 10-K"), of our report dated February 9, 2010, on oil and gas reserves of Gulfport Energy Corporation and its subsidiaries, to all references to our firm in the Form 10-K and to the incorporation by reference of said report in the Registration Statements of Gulfport Energy Corporation on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001) and on Forms S-3 (File No. 333-146988, effective November 13, 2007; File No. 333-143659, effective July 18, 2007; and File No. 333-139480, effective January 23, 2007).

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ DANNY D. SIMMONS
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
March 12, 2010

Exhibit 23.3

CONSENT OF PINNACLE ENERGY SERVICES, LLC

We have issued our report letters dated February 9, 2010 for 2009, on estimates of proved reserves and future net cash flows of certain oil and natural gas properties located in the Permian Basin of West Texas acquired by Gulfport Energy Corporation (“Gulfport”) on December 20, 2007 from ExL Petroleum, LP and certain other sellers. As independent oil and gas consultants, we hereby consent to the inclusion of the information contained in our report letters in this Annual Report on Form 10-K of Gulfport (this “Annual Report”) and to all references to our firm in this Annual Report. We hereby also consent to the incorporation by reference of such information in the Registration Statements of Gulfport on Forms S-8 (File No. 333-135728, effective July 12, 2006; File No. 333-129178, effective October 21, 2005; and File No. 333-55738, effective February 16, 2001) and on Forms S-3 (File No. 333-146988, effective November 13, 2007; File No. 333-143659, effective July 18, 2007; and File No. 333-139480, effective January 23, 2007).

PINNACLE ENERGY SERVICES, LLC

/s/ JOHN PAUL DICK

Name: John Paul Dick
Title: Manager, Registered Petroleum Engineer

March 9, 2010
Oklahoma City, Oklahoma

Exhibit 31.1

CERTIFICATION

I, James D. Palm, Chief Executive Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Gulfport Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statement made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: March 12, 2010

/S/ JAMES D. PALM

James D. Palm
Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Michael G. Moore, Chief Financial Officer of Gulfport Energy Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Gulfport Energy Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statement made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) all significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

Date: March 12, 2010

/S/ MICHAEL G. MOORE

Michael G. Moore

Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PERIODIC REPORT

I, James D. Palm, Chief Executive Officer of Gulfport Energy Corporation (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the period ended December 31, 2009 (the “Report”) fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 12, 2010

/s/ JAMES D. PALM

James D. Palm
Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION OF PERIODIC REPORT

I, Michael G. Moore, Chief Financial Officer of Gulfport Energy Corporation (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2009 (the "Report") fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 12, 2010

/s/ MICHAEL G. MOORE

Michael G. Moore
Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

NETHERLAND, SEWELL & ASSOCIATES, INC.

February 9, 2010

Mr. Mike Moore
Gulfport Energy Corporation
14313 North May Avenue, Suite 100
Oklahoma City, Oklahoma 73134

Dear Mr. Moore:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2009, to the Gulfport Energy Corporation (Gulfport) interest in certain oil and gas properties located in West Cote Blanche Bay Field, St. Mary Parish, Louisiana. It is our understanding that the proved reserves estimated in this report constitute approximately 27.5 percent of all proved reserves owned by Gulfport. The estimates in this report have been prepared in accordance with the definitions and guidelines of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of overhead expenses and future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Gulfport's use in filing with the SEC.

We estimate the net reserves and future net revenue to the Gulfport interest in these properties, as of December 31, 2009, to be:

	Net Reserves		Future Net Revenue ($)	
Category	Oil (Barrels)	Gas (MCF)	Total	Present Worth at 10%
Proved Developed Producing	967,646	540,464	27,469,900	27,025,900
Proved Developed Non-Producing	2,283,124	606,665	39,466,400	30,299,700
Proved Undeveloped	1,776,882	426,165	62,443,800	49,206,300
Total Proved	5,027,652	1,573,294	129,380,100	106,531,900

The oil reserves shown include crude oil and condensate. Oil volumes are expressed in barrels that are equivalent to 42 United States gallons. Gas volumes are expressed in thousands of cubic feet (MCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable reserves that exist for these properties have not been included. No study was made to determine whether possible reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Future gross revenue to the Gulfport interest is prior to deducting state production taxes. Future net revenue is after deductions for these taxes, future capital costs, operating expenses, and abandonment costs but before consideration of federal income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Our estimates of future revenue do not include any salvage value for the lease and well equipment but do include Gulfport's estimates of the costs to abandon the wells and production facilities.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2009. For oil volumes, the average Shell Trading (US) Company West Texas/New Mexico Intermediate posted price of $57.90 per barrel is adjusted for quality, transportation fees, and a regional price differential. For gas volumes, the average Henry Hub spot price of $3.866 per MMBTU is adjusted for energy content, transportation fees, and a regional price differential. As requested, an economic projection is included in the proved developed producing category to account for the incremental income received from certain oil price hedge contracts currently in place. All prices are held constant throughout the lives of the properties.

Lease and well operating costs used in this report are based on operating expense records of Gulfport, the operator of the properties. As requested, lease and well operating costs are limited to direct lease- and field-level costs. Headquarters general and administrative overhead expenses of Gulfport are not included. Lease and well operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers, new development wells, and production equipment. The future capital costs are held constant to the date of expenditure.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the Gulfport interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Gulfport receiving its net revenue interest share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report. Estimates of reserves may increase or decrease as a result of future operations, market conditions, or changes in regulations.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. We used standard engineering and geoscience methods, or a combination of methods, such as performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to establish reserves quantities and reserves categorization that conform to SEC definitions and guidelines. A substantial portion of these reserves are for behind-pipe zones, non-producing zones, and undeveloped locations. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The titles to the properties have not been examined by Netherland, Sewell & Associates, Inc. (NSAI), nor has the actual degree or type of interest owned been independently confirmed. The data used in our estimates were obtained from Gulfport, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting geoscience, field performance, and work data are on file in our office. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding 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. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties and are not employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-002699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Derek F. Newton
Derek F. Newton, P.E. 97689
Vice President

Date Signed: February 9, 2010

By: /s/ Mike K. Norton
Mike K. Norton, P.G. 441
Senior Vice President

Date Signed: February 9, 2010

Exhibit 99.2

February 9, 2010

Gulfport Energy Corporation
14313 N. May Ave., Ste. 100
Oklahoma City, OK 73134

Attn: Mr. Steve Baldwin

Re: Reserves & Economic Evaluation
SEC Year End 2009
Permian Properties

EXECUTIVE SUMMARY

Pursuant to your request, an engineering and economic evaluation was prepared for projected oil and gas reserves associated with interests owned by Gulfport Energy Corporation ("Gulfport") in the Permian entity, operated by Windsor Energy Group, LLC ("Windsor"). The properties include sixty-four (64) Proved Producing (PDP) wells, sixteen (16) Proved Behind-Pipe (PDBP) wells, two (2) Proved Non-Producing (PDNP) wells and one hundred ninety-one (191) Proved Undeveloped (PUD) locations. Remaining reserves and future and present worth values for these properties were calculated as of January 1, 2010. The attached **Exhibit A** lists the wells included in the evaluation as well as other pertinent information.

The total gross and net reserves and future cumulative cashflows, both undiscounted and discounted (at 10%) prior to considering the effects of Federal Income Taxes for all properties, are summarized in TABLE 1 below. Economics were prepared using the yearend 2009 SEC price forecast.

TABLE 1
Reserves and Economic Summary

Reserve Category	# Wells	Rem Net Oil MBbls	Rem Net Gas MMcf	Rem Net NGL MGal	Net Capital M$	Net Cashflow M$	Net Disc PV @ 10%, M$
PDP	64	817	1,556	14,818	0	37,577	21,939
PDBP	16	221	358	3,585	1,200	12,428	6,322
PDNP	2	60	95	994	633	2,636	1,395
PUD	191	6,173	8,885	85,299	120,808	197,324	61,776
Total Proved	**273**	**7,271**	**10,894**	**104,696**	**122,640**	**249,965**	**91,432**

The reserve classifications meet the criteria for Proved reserves under the SEC guidelines as of January 1, 2010. All working and net revenue interests were provided by Gulfport. Historical production and geological data was provided by Windsor and was supplemented by data gathered from public sources. All of the information provided to us or gathered by us was assumed to be accurate and correct and was not independently verified.

Results of the evaluations showing forecasts of production, reserves, revenues, and income for each well are presented in a yearly format, and are attached and made part of this reports appendices. The gross production graphs and forecasts (by well/lease) and a one-line economic summary (by well/lease) of the results from the evaluation are also included in the appendices.

ECONOMIC EVALUATION

FUTURE INCOME

Future net revenue in this report includes deductions for state production taxes. Future net income is after deducting production taxes, future capital investments, and lease operating expenses, but before consideration of any state and/or federal income taxes. No provisions for salvage value or abandonment costs, which are generally assumed to offset each other, were been included in this evaluation. Future net income has not been adjusted for any outstanding loans that may exist or cash on hand or undistributed income. The future net income has been discounted at various annual rates, including the standard ten percent (10%), to determine its “present worth.” The present worth is shown to indicate the effect of time on the value of money.

PRODUCT PRICING

The reserves and economic evaluation was performed using yearend 2009 SEC prices of $61.18/bbl oil, $3.87/mmbtu gas and $0.70/gal NGL, based on WTI at Cushing postings. Product prices were adjusted to reflect BTU content, field losses and usage, and gathering and processing costs. The realized oil price reflects a downward adjustment of $2.34/bbl based on the oil sales contract for 2009 provided by Windsor. The realized gas price reflects a downward adjustment of 6.01%. Oil and gas prices were held constant for the life of the well.

The plant statements for each lease were provided by Windsor and analyzed to determine the natural gas liquids (NGL) Yield and the percent loss of wellhead gas, Shrink factor. These parameters were entered into the economic model to forecast the NGL production.

EXPENSES

Individual well operating expenses for the previous twelve months were taken from actual lease operating statements provided by Windsor. These expenses were analyzed and adjusted to calculate the average re-occurring monthly expense for each well less water disposal costs. Water production for each well was forecasted and expensed at $1.25 per barrel for all areas. A new salt water disposal well in the Bloxom area will be online in March 2010 and the salt water disposal costs were reduced in the economic analysis to $0.25/bbl.

FUTURE WELL INVESTMENTS

Future well drilling and completion costs were provided by Windsor and estimated to be $1.265 MM per well based on historical data and current AFE’s provided. Recompletion costs were assumed to be $100,000 per well. Capital timing for the first three (3) years was provided by Windsor. Pinnacle cannot be responsible for capital costs that exceed or are less than these estimates.

RESERVE DETERMINATION

RESERVE DISCUSSION

Remaining recoverable reserves are those quantities of petroleum that are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty depending primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty is conveyed by classifying reserves as Proved (highly certain) or Non-Proved (less certain). Detailed reserve definitions are provided in attachments to this report.

The estimated reserves and revenues shown in this report were determined by SEC standards for Proved Developed Producing (PDP) reserve category. Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs with defined limits and under current economic conditions, operating methods, and government regulations.

Proved Developed Producing (PDP) is assigned to wells with sufficient production history to allow material balance and decline curve analysis to be the primary methods of estimation. PDP reserves are the most reliable reserves, generally with a high degree of confidence (>90%) that actually recovered quantities will equal or exceed published reserve estimates. Proved Developed Non-Producing (PNP) reserves include zones that have been penetrated by drilling but have not produced sufficient quantities to allow material balance or decline curve analysis with a high degree of confidence. This category includes Proved Developed Behind-Pipe (PNPBP) zones and tested wells awaiting production equipment (PNP).

Proved Undeveloped (PUD) reserves are those quantities of petroleum that are estimated to be recovered from undrilled acreage (locations) in a continuous portion of the Proved Developed reservoir as defined by offsetting PDP wells and geological interpretations. The Proven Undeveloped and Non-Producing wells were forecasted based on geological data presented, volumetric calculations, and analog comparisons to existing completions. Non-Proven (Probable) Undeveloped locations have been evaluated to be likely productive but do not meet SEC criteria to be classified as Proved at this time.

GENERAL

The reserves and values included in this report are estimates only and should not be construed as being exact quantities. The reserves were estimated using industry accepted engineering practices and were primarily based on historical rate decline analysis determined from existing producers in an analogous field. When possible and practical, pressure tests, material balance techniques and analogies were integrated into the reserve estimates. As additional pressure and production performance data becomes available, reserve estimates may increase or decrease in the future.

The revenue from these reserves and the actual costs to produce may be more or less than the estimated amounts and may consequently cause an increase or decrease in future reserve estimates. In evaluating the information available for this analysis, items excluded from consideration were all matters as to which legal or accounting, rather than engineering interpretation, may be controlling. Because of governmental policies and uncertainties of supply and demand, the prices actually received for the reserves included in this report and the costs incurred in recovering such reserves may vary from the price and cost assumptions referenced. Accordingly, note that as in all aspects of oil and gas evaluation the accuracy of any reserve estimate is solely a function of engineering interpretation and judgment and should be accepted with the understanding that future production or unanticipated events subsequent to this report could justify revision of these reserve estimates – either increases or decreases.

Pinnacle Energy Services, L.L.C. is an established petroleum engineering consulting firm. We hereby confirm that neither this firm, it's affiliates, nor any of its employees, members, officers, or directors has, or is committed to acquire any interest, directly or indirectly, in the properties covered by this report, in any partnership, any general partner of the partnerships, nor is this firm or any employee, member or officer, or director thereof otherwise affiliated with any partnership or any such general partner. This report was completely, independently prepared by Pinnacle Energy Services L.L.C. and our engagement and payment for services in connection with this report is independent of the outcome and not on a contingent basis.

The titles to the properties have not been examined nor has the actual degree or type of interest owned been independently confirmed. Pinnacle Energy Services personnel have not conducted any field production test or field inspection of the properties as this is not usually considered necessary for the purpose of this report. Additionally, an "audit" of the information obtained from public sources or provided by the operator and/or owner of these properties has not been conducted to confirm its accuracy.

This report has been prepared for the exclusive internal use of Gulfport Energy, Corporation and shall not be used otherwise without the written consent of Pinnacle Energy Services, L.L.C. Additional information reviewed or used in this evaluation will be retained and is available for review by authorized parties at any time. Pinnacle Energy Services, L.L.C. can take no responsibility for the accuracy of the data used in the analysis, whether gathered from public sources or otherwise.

Pinnacle Energy Services, LLC

/s/ John Paul (J.P.) Dick

John Paul (J.P.) Dick, P.E.
Petroleum Engineer

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