GULFPORT ENERGY CORP
Form 10-K
March 17, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007
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 x

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

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

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 30, 2007, based on the closing price of the common stock on the NASDAQ Global Select Market on June 29, 2007, the last business day of the registrant s most recently completed second fiscal quarter ($19.98 per share) was $405,264,130.

As of March 3, 2008, 42,550,031 shares of the registrant s common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation s Proxy Statement for the 2008 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

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FORWARD-LOOKING STATEMENTS

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

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

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

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PART I

ITEM 1. 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. We have also recently acquired strategic assets 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.

In 2007, at our WCBB field, we drilled 26 wells and recompleted 60 existing wells for a total cost of $57.9 million as of December 31, 2007. Of our 26 new wells drilled at WCBB in 2007, 22 were completed as producing wells and four were non-productive. As of March 1, 2008, we had drilled two new wells at WCBB, both of which are producing and had recompleted 14 wells during 2008. During 2008, we intend to drill a total of eight to ten wells, recomplete 44 wells and conduct other activities at our WCBB field for an estimated aggregate cost of $21 to $23 million. In December 2007, production at WCBB was 105,922 net barrels of oil equivalent, or BOE, or an average of 3,417 BOE per day, 93% of which was from oil and 7% of which was from natural gas. In February 2008, our average net daily production at WCBB was 3,622 BOE, 95% of which was from oil and 5% of which was from natural gas.

In 2007, at our East Hackberry field, we drilled nine wells in Lake Calcasieu and three wells on land and recompleted two existing wells for a total cost of $62.4 million as of December 31, 2007. Of the 12 wells drilled during 2007, ten were completed as producing wells and two were non-productive. As of March 1, 2008 at East Hackberry, we had drilled one additional well in Lake Calcasieu, which is now producing, and had recompleted three existing wells. We intend to drill three to five additional land wells, recomplete one additional well and conduct other activities in 2008 for an aggregate estimated cost of $17 to $19 million. In December 2007, net production at East Hackberry was 26,850 BOE, or an average of 867 BOE per day, 70% of which was from oil and 30% of which was from natural gas. In February 2008, our average net daily production at East Hackberry was 735 BOE, 80% of which was from oil and 20% of which was from natural gas.

On December 20, 2007, we completed the acquisition of strategic assets in West Texas in the Permian Basin for approximately $85 million, with an effective date of November 1, 2007. Through this transaction, Gulfport acquired 4,100 net acres with production at the time of acquisition of approximately 800 net BOE a day from 32 gross wells, predominately from the Wolfcamp formation. Existing production is approximately 64% oil, 23% natural gas liquids and 13% natural gas. At December 31, 2007, Pinnacle Energy Services LLC, an independent petroleum engineering firm, estimated that proved reserves net to our interest in these assets were approximately 6.6 million BOE, of which 19.5% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 92 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. We expect that approximately 17 to 22 net wells will be drilled on this acreage in 2008. The wells are expected to be drilled to approximately 10,200 feet at an estimated average gross completed well cost of $1.7 million.

During the third quarter of 2006, we, through our wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% interest in Grizzly Oils Sands ULC, or Grizzly, a Canadian unlimited liability company. The remaining interests in Grizzly are owned by entities controlled by Wexford Capital LLC, or Wexford, an affiliate of ours. 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. As of March 1, 2008, Grizzly had approximately 511,000 acres under lease. Grizzly drilled 62 core holes during the 2006/2007 winter delineation drilling season and tested three separate lease blocks. Future plans currently include acquiring additional leases, drilling approximately 55 to 60 additional core holes and a seismic program during the 2007/2008 winter drilling season and initial planning for the construction of a 10,000 barrel per day steam assisted gravity drainage facility, or SAGD, that could lead to initial production in 2011. Permitting for this initial SAGD facility is expected to commence later in 2008.

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. 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.

As of December 31, 2007, we had 29.2 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 $821million and associated standardized measure of discounted future net cash flows of approximately $668.3 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, 2007 reflecting our net interest in our principal producing oil and natural gas properties along the Louisiana Gulf Coast and in the Permian Basin in West Texas.

		Producing Wells (2)		Non-Producing Wells		Developed Acreage (3)		Proved Reserves		
Field	**NRI/WI (1) Percentages**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gas Mboe**	**Oil Mboe**	**Total Mboe**
West Cote Blanche Bay (4)	78.665/100	111	111	166	166	5,668	5,668	15,891	15,135	17,783
E. Hackberry (5)	79.424/100	12	12	82	82	3,265	3,265	2,776	4,119	4,582
W. Hackberry	87.5/100	3	3	24	24	592	592		158	158
Permian	37.5/50	32	16			2,560	1,280	5,587	5,699	6,630
Overrides/Royalty Non-operated	Various	18	0.8	16	0.7	4,956	586	5	4	5
Total		176	142.8	288	272.7	17,041	11,391	24,259	25,115	29,158

(1) Net Revenue Interest (NRI)/Working Interest (WI).

(2) Includes 30 gross and net wells at WCBB that are producing intermittently.

(3) Developed acres are acres spaced or assigned to productive wells. Approximately 87% of our acreage is developed acreage and has been perpetuated by production. We have 1,100 and 2,820 net undeveloped acres in the East Hackberry field and the Permian Basin, respectively.

(4) We have a 100% working interest (78.665% 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) Does not include an additional 3,233 acres under an option we exercised which will increase our acreage position significantly to approximately 7,598 acres. State approval was obtained on February 27, 2008, and we are working with the state to finalize the leases.

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West Cote Blanche Bay Field

Location and Land

The WCBB field is located approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. We own a 100% working interest (78.665% 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 900 wells drilled as of December 31, 2007, 809 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, 2007, we drilled 120 new wells, 14 of which were non-productive, for an 88% success rate. As of December 31, 2007, estimated field cumulative gross production was 187.4 MMBOE and 235.5 billion cubic feet, or Bcf, of gas. Of the 900 wells drilled in WCBB as of December 31, 2007, 81 were producing, 166 were shut-in, 30 were producing intermittently and five were being used as salt water disposal wells. The other 618 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 900 wellbores that had been drilled in the field as of December 31, 2007, 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

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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 includes 111 PUD wells. The drilling schedule used in the reserve report anticipates that all of those wells will be drilled by 2019.

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 2007, we drilled 26 wells and recompleted 60 existing wells at WCBB. Of these 26 new wells, 22 were completed as producers, and four were non-productive. As of March 1, 2008, we had drilled two new wells, both of which are producing, and had recompleted 14 wells during 2008. Of the 22 wells completed in 2007, ten were considered deep wells. The 22 productive wells, with total depths ranging from 6,107 to 10,464 feet, have approximately 2,716 feet of aggregate apparent net pay. The other four wells were non-productive, including one exploratory well that was drilled to satisfy our drilling commitment with the State of Louisiana to hold the non-productive portions of WCBB. We anticipate drilling a total of eight to ten wells and recompleting 44 wells at WCBB during 2008.

Production Status

In December 2007, production at WCBB was 105,922 net BOE, or an average of 3,417 BOE per day, 93% of which was from oil and 7% of which was from natural gas. In February 2008, our average net daily production at WCBB was 3,622 BOE, 95% of which was from oil and 5% 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 4,365 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. In addition, we exercised our option to acquire an additional 3,233 acres at the Hackberry field. The option will increase our acreage position significantly to approximately 7,598 acres. State approval was obtained on February 27, 2008, and we are working with the state to finalize the leases.

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 2007 was over 263,000 barrels of oil and 330 Bcf of casinghead gas production. There have been a total of 182 wells drilled on our portion of the field. As of December 31, 2007, 12 wells had daily production, 82 were shut-in and two had been converted to salt water disposal wells. The remaining 86 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. Given that drilling activities at the East Hackberry field prior to our acquisition of the field in 1997 were undertaken without the benefit of modern seismic information, we believe that this 3-D seismic data will enhance our probability of drilling success. We continue to evaluate the 3-D seismic data to identify additional drilling locations. During 2007 at East Hackberry, we drilled nine wells in Lake Calcasieu and three wells on land and recompleted two existing wells. Of the 12 wells drilling during 2007, ten were completed as producing wells and two were non-productive. As of March 1, 2008 at East Hackberry, we had drilled one additional well in Lake Calcasieu, which is now producing, and had recompleted three existing wells. We intend to drill three to five additional land wells and recomplete one additional well at East Hackberry during 2008. Drilling activity in this field during 2008 will target measured depths of up to 13,000 feet using directional drilling techniques.

Production Status

In December 2007, net production at East Hackberry was 26,850 BOE, or an average of 867 BOE per day, 70% of which was from oil and 30% of which was from natural gas. In February 2008, our average net daily production at East Hackberry was 735 BOE, 80% of which was from oil and 20% of which was from natural gas.

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 2007 was 227 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.

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Geology

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

Production Status

In December 2007, net production at West Hackberry was 641 BOE, or 21 BOE per day. In February 2008, our average net daily production at West Hackberry was 21 BOE.

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. 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 Bain is semi-arid mesquite-mixed grassland steppe.

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 decided to drill completely through the Wolfcamp section as Devonian wells. Henry 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 s Wolfcamp team formed their own private company, ExL Petroleum, and began replicating Henry 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. Currently, we hold interests in thirty-two 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.

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Wolfberry well reserves are typically approximately 80% from the Wolfcamp section and 20% from the Spraberry section, consisting of approximately 64% oil, 23% natural gas liquids, and 13% natural gas. Pinnacle Energy Services, LLC, an independent petroleum engineering firm, has estimated that at December 31, 2007, proved reserves net to our interest in these assets were approximately 6.6 million BOE, of which 19.5% were classified as proved developed producing, or PDP. Proved undeveloped, or PUD, reserves included in this estimate were from 92 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. Wells to be drilled will be approximately 10,200 feet at an estimated average gross completed well cost of $1.7 million. The gross estimated ultimate recovery, or EUR, as estimated by Pinnacle Energy Services, LLC, is expected to average gross 146,000 BOE per well with an average net revenue interest in the field of approximately 75%. We have a 50% working interest and approximately 37.5% net revenue interest in the field.

Production Status

At the date of acquisition, there was production of approximately 800 net BOE a day from 32 gross, producing wells. During February 2008, average net production to Gulfport was 531 BOE a day.

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

We have identified 178 gross future development drilling locations. We expect approximately 17 to 22 net wells to be drilled in 2008. The wells are expected to be drilled to approximately 10,200 feet at an estimated average gross completed well cost of $1.7 million.

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%	2	5
Bayou Pigeon	Iberia	6.250%	0%	5	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 $2,400,000. 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, 2007, we paid $88,000 in cash calls, bringing our total investment in Tatex (including previous investments) to $3,553,000. 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. Current net production is approximately 100 Mcf per day. Hess Corporation operates the field with a

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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%. Proved reserves from the Phu Horm field, net to our interest, are 3.5 BCF of gas and 10,000 barrels of oil. 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.

Williston Basin. During 2005, we purchased a 20% ownership interest in Windsor Bakken, LLC, or Bakken. The remaining interests in Bakken are owned by entities controlled by Wexford. In 2005 and 2006, Bakken acquired leases on undeveloped acreage in the Williston Basin areas of western North Dakota and eastern Montana. At December 31, 2007, our net investment in Bakken was $2,468,000. We are currently participating in the drilling of nine wells and have interests in eight producing wells with an average working interest of 1.55%.

Marquiss Field. In February 2005, but effective as of December 1, 2004, we acquired our interest in the Marquiss field, an approximately 9,500 net acre coalbed methane play in Campbell County, Wyoming, for $375,000. As of December 31, 2006, the Marquiss field included a total of 162 wells, all of which were shut-in as a result of the economic status of the field as a result of a decline in natural gas prices for this field. The wells (when on line) produced from multiple horizons with additional upside potential from deeper coals and operational efficiencies. Our interest in the Marquiss field was sold in February 2007 for $500,000.

Grizzly Oil Sands. During the third quarter of 2006, we, through our wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% 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 511,000 acres under lease and our total net investment in Grizzly was $27,801,000 at December 31, 2007. Grizzly drilled 62 core holes during the 2006/2007 winter delineation drilling season and tested three separate lease blocks using up to four different rigs. Future plans currently include acquiring additional leases, drilling approximately 55 to 60 additional core holes and a seismic program during the 2007/2008 winter drilling season and initial planning for the construction of a 10,000 barrel per day SAGD facility that could lead to initial production in 2011. Gross capital expenditures for such a production facility are currently estimated to be approximately $325 million.

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 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 is being sold in accordance with the posted price for West Texas/New Mexico Intermediate crude plus Platt s trade month average P+ value, plus or minus the Platt s WII/LLS differential less $3.70 per barrel for transportation. During 2007, we sold 99% of our oil production to Shell and 69% of our natural gas production to Chevron and 23% of our natural gas production to Hilcorp Energy Company and during 2006, we sold 100% of our oil production to Shell and 96%

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of our natural gas production to Chevron. During 2005, we sold 99% of our oil production to Shell and 88% of our natural gas production to Chevron. There can be no assurance, however, that we will 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 2007, we entered into 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, we 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 costs. In addition, we have entered into agreements to sell 3,500 barrels of production per day for the months of January through May 2008 at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, we have 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, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $81.37 per barrel before transportation costs. For August 2008, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $82.44 per barrel before transportation costs. For the periods of September 2008 through December 2008, we have entered into forward sales contracts for the sale of 3,000 barrels of production per day in each such period at weighted average daily prices of $82.20 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 60% of our estimated production for January through December 2008. For the period of January through December 2009, we entered into agreements to sell 2,500 barrels of production per day at a weighted average daily price of $84.62 per barrel before transportation costs. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

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 and West Texas. 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 federal, state and local 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 to implement and enforce such laws, which often require difficult

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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. 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 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 current 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 the requirements of RCRA and related state and local laws and regulations, 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 deposited.

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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 proscriptions 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 toxic 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.

Operational Hazards and Insurance

Our operations are subject to all of the risks normally incident to the production of oil and natural gas, including 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 to persons. 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, 2007, we had 70 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, 2007 and 2006, expenses reimbursed to us under these arrangements were

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$11,153,000 and $12,738,000, 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 $30.83 per barrel, or bbl, in January 2004 to a high of $102.20 per bbl on March 6, 2008. The Henry Hub spot market price of natural gas has ranged from a low of $4.20 per million British thermal units, or MMBtu, in October 2006 to a high of $13.93 per MMBtu in October 2005. On December 31, 2007, the West Texas Intermediate posted price for crude oil was $92.50 per bbl and the Henry Hub spot market price of natural gas was $6.80 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.

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 make and expect to continue 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 cannot assure you that we will have sufficient resources to undertake our exploration and development activity, production and acquisition of oil and natural gas reserves, that our exploratory projects or other replacement activities will result in significant additional reserves or that we will 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 on schedule or at budgeted cost or at all.

During the third quarter of 2006, we, through our wholly owned subsidiary Grizzly Holdings Inc., purchased a 24.9999% 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 511,000 acres under lease and as of December 31, 2007, our total net investment in Grizzly was approximately $27.8 million. Grizzly drilled 62 core holes during the 2006/2007 winter delineation drilling season and tested three separate lease blocks using up to four different rigs. Future plans currently include acquiring additional leases, drilling approximately 55 to 60 additional core holes and a seismic program during the 2007/2008 winter drilling season and initial planning for the construction of a 10,000 barrel per day SAGD facility that could lead to initial production in 2011. Gross capital expenditures for such a production facility are currently estimated to be approximately $325 million. This is a complex project and financing has not yet been secured. There can be no assurance that this project can be completed on schedule, 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, and at the present time there is a shortage of drilling rigs, equipment, supplies and personnel. The costs and delivery times of rigs, equipment and supplies has increased as drilling activities have increased. In addition, demand for, and wage rates of, qualified drilling rig crews have risen 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.

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

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures, including many factors beyond our control. The reserve information incorporated by reference in this prospectus represents only estimates based on reports prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2007 with respect to our WCBB field, by Pinnacle Energy Services, LLC 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.

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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 prices and costs in effect on the day of estimate. 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.

There are numerous uncertainties inherent in estimating quantities of bitumen reserves and resources and no assurance can be given that indicated level of reserves or recovery of bitumen will be realized.

There are numerous uncertainties inherent in estimating quantities of bitumen reserves and resources, including many factors beyond our or Grizzly s control, and no assurance can be given that the indicated level of reserves or recovery of bitumen will 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 inherent 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. No assurance can be provided as to the gravity or quality of bitumen to be produced from Grizzly s lands.

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 due to circumstances beyond our control. 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

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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. The increasing demand for transportation barges in the Louisiana Gulf Coast region has adversely impacted our ability to transport our oil production from the tank batteries in our field to shore for delivery. This has required us to shut in or curtail production from time to time as we have only limited storage capacity in the 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.

Substantially all of our producing properties are 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 cannot assure you that we will 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 comprise an estimation of part of our future drilling plans over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified over 200 drilling locations on our Louisiana 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 inherent in 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 have been filed against us, among other parties. Information with respect to this litigation is incorporated by reference in this Form 10-K. Litigation is inherently uncertain and its outcome cannot be predicted at this time; however, if this litigation is not resolved in a manner that is favorable to us, our financial condition and results of operations may be negatively impacted.

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In accordance with customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. We cannot assure you that our insurance will be adequate to cover any losses or liabilities we may suffer. We also cannot predict the continued availability of insurance, or its availability at premium levels that 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.

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 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. At December 31, 2007, our WCBB production was being sold in accordance with the posted price for West Texas/New Mexico Intermediate crude plus Platt s trade month average P+ value, plus or minus the Platt s WII/LLS differential less $3.70 per Bbl for transportation. For the year ended December 31, 2007 and the year ended December 31, 2006, we sold approximately 99% and 100%, respectively, of our oil production to Shell and 69% and 96%, respectively, of our natural gas production to Chevron. During 2007, we sold approximately 23% of our natural gas production to Hilcorp Energy Company. During 2005, we sold 99% of our oil production to Shell and 88% of our natural gas production to Chevron. There can be no assurance that we will 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 unescalated year-end prices and costs, 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.

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 reduce our exposure to short-term fluctuations in the price of oil and natural gas, we periodically enter into hedging arrangements. Currently, we have entered into agreements to sell 3,500 barrels of production per day for the months of January through May 2008 at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, we have 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, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $81.37 per barrel before transportation costs. For August 2008, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $82.44 per barrel before transportation costs. For the periods of September 2008 through December 2008, we have entered into forward sales contracts for the sale of 3,000 barrels of production per day in each such period at weighted average daily prices of $82.20 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 60% of our estimated production for January through December 2008. For the period of January through December 2009, we entered into agreements to sell 2,500 barrels of production per day at a weighted average daily price of $84.62 per barrel before transportation costs. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

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. Management cannot predict the impact of the changing demand for oil and gas services and products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to the requirements of Section 404 of the Sarbanes-Oxley Act. If the costs related to such compliance are significant, our profitability, stock price and results of operations and financial condition could be materially adversely affected.

Commencing with our fiscal year ended December 31, 2007, we became subject to Section 404 of the Sarbanes-Oxley Act of 2002, or Section 404, which requires that we document and test our internal control over financial reporting and issue management s assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm audit our internal control over financial reporting. We are required to evaluate our existing controls against the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO. The out-of-pocket costs, the diversion of management s attention from running the day-to-day operations and operational changes caused by the need to comply with the requirements of Section 404 have been significant. If the future time and costs associated with such compliance exceed our current expectations, our results of operations could be adversely affected. If we fail to fully comply with the requirements of Section 404 or if we determine that we have a material weakness or significant deficiencies, or if our auditors disagree with our assessment in connection with the presentation of our financial statements, the accuracy and timeliness of the filing of our periodic reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness or significant deficiency in our internal control over financial reporting could result in an increased chance of fraud, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Due to inherent limitations, there can be no assurance that our system of disclosure and internal controls and procedures will be successful in preventing all errors and fraud, or in making all material information known in a timely manner to management.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and internal controls will prevent all errors and fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the

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control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost effective control system, misstatements due to error or fraud may occur and not be detected that could have a material adverse effect on our business, results of operations and financial condition.

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 control a significant percentage of our common stock, and their interests may conflict with those of our other stockholders.

As of December 31, 2007, our executive officers and directors, in the aggregate, beneficially owned approximately 4% 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.

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We can give no assurances as to the market for our common stock.

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. We cannot assure you that an active trading market will develop, or if it does, that it will 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 there can be no assurance that we will achieve sufficient earnings to 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, 2007, we had a net operating loss, or NOL, carry forward of approximately $93 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 3, 2008, there were 42,550,031 shares of our common stock issued and outstanding, excluding 77,210 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

The oil and natural gas reserve information set forth below represents estimates of our proved oil and natural gas reserves as prepared by the independent engineering firm of Netherland, Sewell & Associates, Inc., or NSAI, with respect to WCBB, our primary field, as prepared by Pinnacle Energy Services, LLC with respect to our assets in the Permian Basin in West Texas and by our personnel with respect to our other interests. 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.

The following table sets forth estimates of our proved oil and natural gas reserves at December 31, 2007, 2006 and 2005. Reserve estimates at December 31, 2007 were prepared by NSAI with respect to our WCBB field (61% of proved reserves PV-10 value at December 31, 2007), by Pinnacle Energy Services, LLC with respect to our assets in the Permian Basin in West Texas (18% of proved reserves PV-10 value at December 31, 2007) and by our personnel with respect to our Hackberry fields and our overrides and non-operated interests (21% of proved reserves PV-10 value at December 31, 2007). The reserve estimates at December 31, 2006 were prepared by NSAI with respect to our WCBB field (82% of proved reserves PV-10 value at December 31, 2006) and by our personnel with respect to our Hackberry fields and our overrides and non-operated interests (18% of proved reserves PV-10 value at December 31, 2006). Hackberry reserve estimates at December 31, 2005 were prepared by NSAI.

	December 31, 2007			December 31, 2006			December 31, 2005		
	Developed	**Undeveloped**	**Total**	**Developed**	**Undeveloped**	**Total**	**Developed**	**Undeveloped**	**Total**
Oil (MBbls)	7,116	17,999	25,115	4,876	14,816	19,692	4,308	15,234	19,542
Gas (MMcf)	6,746	17,513	24,259	4,077	16,724	20,801	3,758	18,023	21,781
Mboe	8,240	20,918	29,158	5,556	17,603	23,159	4,934	18,238	23,172
PV-10 (in millions) (1)	$ 294.7	$ 526.5	$ 821.2	$ 120.0	$ 279.4	$ 399.4	$ 135.9	$ 321.0	$ 456.9
Standardized measure (in millions) (2)			$ 668.3			$ 352.6			$ 369.8

(1) 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 economic conditions prevailing at December 31, 2007. The estimated future production in our WCBB and Hackberry fields is priced at December 31, 2007, 2006 and 2005, without escalation

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using $92.50 per barrel and $6.80 per MMBtu, $57.75 per barrel and $5.64 per MMBtu and $57.75 per barrel and $10.08 per MMBtu, respectively, 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,		
	2007	**2006**	**2005**
Standardized measure of discounted future net cash flows	$ 668,295,000	$ 352,648,000	$ 369,824,000
Add: Present value of future income tax discounted at 10%	152,949,000	46,804,000	87,086,000
PV-10 value	$ 821,244,000	$ 399,452,000	$ 456,910,000

(2) 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, or 3.5 Bcf of gas and 10,000 barrels of oil at December 31, 2007. For further discussion of our interest in Tatex, see Item 1. Description of Business Additional Properties.

Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

Total proved reserves increased to 29,158 Mboe at December 31, 2007 from 23,159 Mboe at December 31, 2006. Total proved reserves decreased slightly to 23,159 Mboe at December 31, 2006 from 23,172 Mboe at December 31, 2005. The change in 2007 reserves, as compared to 2006 reserves, is mainly attributable to the acquisition of the Permian assets in December 2007. The decrease in 2006 reserves, as compared to 2005 reserves, is attributable to reserve revisions and reductions related to our 2006 production, mostly offset by reserve additions from our 2006 drilling activity.

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Production, Prices, and Production Costs

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

	2007	2006	2005
Production Volumes:			
Oil (MBbls)	1,501	870	517
Gas (MMcf)	816	677	575
Oil Equivalents (Mboe)	1,637	983	613
Average Prices:			
Oil (per Bbl)	$ 66.71(1)	$ 64.43(1)	$ 46.39(1)
Gas (per Mcf)	$ 7.40	$ 6.20	$ 5.98
Oil Equivalents (per Mboe)	$ 64.86	$ 61.30	$ 44.75
Production Costs:			
Average Production Costs (per Boe)	$ 10.18(2)	$ 10.86(2)	$ 12.49(2)
Average Production Taxes (per Boe)	$ 7.74	$ 7.50	$ 5.91
Total Production Costs (per Boe)	$ 17.92	$ 18.36	$ 18.40

(1) Includes fixed contract prices of:

January June 2005	$ 33.10
July December 2005	$ 39.70
January December 2006	$ 64.05
June December 2007	$ 66.10

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 represents approximately 43% of our total oil sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2006 would have been $65.56 per barrel and $62.30 per barrel of oil equivalent. The total volume hedged for 2006 represents approximately 62% of our total oil sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2005 would have been $56.17 per barrel and $52.99 per barrel of oil equivalent. Also includes financial hedge contracts with an average mark-to-market value of approximately $50,000 per month for the months of July-December 2005 and approximately $82,000 per month for the months of January-December 2006.

(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, 2007:

Field	NRI/WI (1) Percentages	Producing Wells (2) Gross	Producing Wells (2) Net	Non-Producing Wells Gross	Non-Producing Wells Net	Developed Acreage (3) Gross	Developed Acreage (3) Net
West Cote Blanche Bay (4)	78.665/100	111	111	166	166	5,668	5,668

E. Hackberry (5)	79.424/100	12	12	82	82	3,265	3,265
W. Hackberry	87.5/100	3	3	24	24	592	592
Permian	37.5/50	32	16			2,560	1,280
Overrides/Royalty Non-operated	Various	18	0.8	16	0.7	4,956	586
Total		176	142.8	288	272.7	17,041	11,391

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(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes 30 gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 87% of our acreage is developed acreage and has been perpetuated by production. We have 1,100 and 2,820 net undeveloped acres in the East Hackberry field and the Permian Basin, respectively.
(4) We have a 100% working interest (78.665% 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) Does not include an additional 3,233 acres under an option we exercised which will increase our acreage position significantly to approximately 7,598 acres. State approval was obtained on February 27, 2008, and we are working with the state to finalize the leases.

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.

	2007		2006		2005 (1)	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	62	62	18	18	11	11
Dry			1	1		
Total	62	62	19	19	11	11
Development:						
Productive	23	23	24	24	16	16
Dry	3	3	2	2		
Total	26	26	26	26	16	16
Exploratory:						
Productive	9	9	1	1		
Dry	3	3	1	1	1	1
Total	12	12	2	2	1	1

(1) Includes seven gross and net wells that were drilled during 2005 but not completed due to the damage caused by Hurricane Rita. For further discussion of the impact of Hurricane Rita, see Item 6. Management s Discussion and Analysis of Financial Condition and Results of Operations Impact of Hurricane Rita.

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.

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ITEM 3. LEGAL PROCEEDINGS

The Louisiana State Mineral Board, or LSMB, is disputing our royalty payments to the State of Louisiana resulting from the sale of oil under fixed price contracts. The LSMB maintains that we paid approximately $1,400,000 less in royalties under the fixed price contracts than the royalties we would have had to pay had we sold the oil at prevailing market rates. We denied any liability to the LSMB for underpayment of royalties and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay royalties based upon the sales proceeds from those contracts. We have met with the Attorney General on several occasions and recently reached a mutual settlement. The settlement requires us to pay $250,000, which has been accrued in accounts payable and accrued liabilities in the accompanying consolidated balance sheet and all future royalties will be paid at market price, regardless of the presence of fixed price contracts. The settlement was approved during the LSMB s February 2008 session, and we are currently awaiting the settlement and release documentation from the LSMB to close this matter.

Litigation

In November 2006, Cudd Pressure Control, Inc., or Cudd, filed a lawsuit against us and Great White Pressure Control LLC, an affiliate of ours, among others, 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 alleges RICO violations and several other causes of action relating to an affiliate company s employment of several former Cudd employees and seeks unspecified monetary damages and injunctive relief. The defendants in the suit are Ronnie Roles, Rocky Roles, Steve Winters, Bert Ballard, Nelson Britton, Michael Fields, Steve Bickle, Great White Pressure Control LLC, and us. On stipulation by the parties, the plaintiff s RICO claim was dismissed without prejudice by order of the court on February 14, 2007. Co-defendant, Steve Bickle, was dismissed from the case on July 18, 2007. The case against us was stayed by order of the court on July 31, 2007. The court further ordered co-defendant, Great White Pressure Control, to move for summary judgment by August 24, 2007. Cudd was ordered to respond by September 14, 2007. We filed a motion for summary judgment on October 5, 2007. Plaintiff filed a response on November 15, 2007, and we filed a reply on November 21, 2007. We are currently awaiting the ruling from the Court.

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 lawsuit alleges a breach of fiduciary duty by us and our directors in connection with the pricing of the 2004 rights offering. We received service of this matter on August 10, 2007. By mutual agreement of the parties, we were not required to respond until notified by the plaintiff, which was received on January 16, 2008. Plaintiff filed an amended complaint on January 15, 2008, and we filed a motion to dismiss in early February 2008.

In July 2007, Michael Tripkovich filed suit in the 16th Judicial District Court of the Parish of St. Martin, Louisiana, against 113 entities, including us, alleging his contraction of chronic myeloid leukemia (CML) was caused by exposure to various substances while maintaining natural gas compressors over a nineteen year period. We were served on July 23, 2007 and filed a response accordingly. The suit is currently in the early phases of discovery. We have no record that Mr. Tripkovich was ever employed by our company. No other deadlines have been set at this time.

In October 2006, an accident occurred north of the our production facilities in the WCBB field in southern Louisiana involving two contracted vessels that were performing work on behalf of us in the field. A tugboat, the M/V Miss Megan, 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. The following lawsuits relating to this incident are currently pending before the courts:

- On October 13, 2006, Athena Construction LLC, or Athena, filed a limitation action in the United States District Court for the Eastern District of Louisiana, alleging that all losses and damages as a result of the pipeline incident were incurred without fault on its part. Furthermore, Athena claims the benefit of the limitation of liability provided for in 42 U.S.C. § 183 and seeks an injunction restraining filing

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commencement and further prosecution in any court of any lawsuit against Athena related to the pipeline incident. The limitation of liability action was subsequently transferred to the United States District Court for the Western District of Louisiana, which is where the case remains pending. On December 20, 2006, 4-K Marine LLC, as owner of the M/V Miss Megan, and Central Boat Rentals, Inc., as operator of the M/V Miss Megan also filed a limitation action in the Western District. On January 10, 2007, the Athena and the 4-K/Central Boat limitation proceedings were consolidated by order of the court. On May 5, 2007, Diamondback Energy, an affiliate of ours, filed an intervener with the Court to become a party to the suit. The remaining parties filed claims on July 9, 2007, which included claims by Nicholas Aucoin, one of the initial responders to the scene of the accident. A record hearing was held on August 13, 2007, to discuss the status of the consolidated matters and a subsequent work plan was filed on October 3, 2007. No other deadlines have been set.

On October 16, 2006, a lawsuit was filed in the 16th Judicial District Court for the Parish of St. Mary, Louisiana against us, Athena, and Central Boat seeking compensatory and punitive damages for claims related to the death of the plaintiff s husband, a crewmember on the Athena barge. The suit alleges that the husband s death was caused by the defendants negligence and the unseaworthiness of the barge to which he was assigned. Pursuant to the Blanket Time Charter between us and Central Boat, Central Boat tendered the defense and indemnification of the lawsuit to us. On November 2, 2006, all proceedings were stayed as a result of the limitation of liability action discussed above. Settlement was reached during mediations held in December 2007. We are currently working to obtain settlement approvals and releases within the next 30 to 45 days.

On October 22, 2006, a lawsuit was filed in United States District Court for the Southern District of Texas, Galveston Division against us, Central Boat, Diamondback Energy Services LLC, an affiliate of ours, Chevron Pipeline Company, Chevron USA, Inc., and ChevronTexaco Pipeline Holdings, Inc. This lawsuit is a result of the death of three individuals. These individuals were employed by Athena and were on the Athena barge at the time of the accident. The plaintiffs seek compensatory and punitive damages as a result of the alleged negligence of defendants. Central Boat has tendered the defense and indemnification of this lawsuit to us. On April 30, 2007, an order was filed transferring the case to the Western District of Louisiana. A successful settlement was reached during mediations held in December 2007. We are currently working to obtain settlement approvals and releases within the next 30 to 45 days.

On February 2, 2007, a lawsuit was filed in the United States District Court for the Western District of Louisiana, Lafayette Division against Chevron Pipeline Company, Chevron USA Inc., Chevron Texaco Pipeline Holdings, Inc., Chevron Natural Gas Services Inc., Diamondback Energy Services LLC, an affiliate of ours, and us. The suit was filed on behalf of April Hummel, individually and as the representative of the minor, Aleya Hummel, the surviving child of Terry Abraham who died in the accident. On March 27, 2007, we filed our answer. On September 2, 2007, the case was stayed by order of the Court. A successful settlement was reached in mediations held in November 2007. We are currently working to obtain settlement approvals and releases.

On October 15, 2007, Brian Dumesnil filed suit in the 16th Judicial District Court for the Parish of St. Mary, Louisiana, against us, Chevron USA, Chevron Texaco Pipeline Holdings, Chevron Natural Gas, Diamondback Energy Services and the Estate of Timothy Tauzin. Mr. Dumesnil was employed by Athena and was on the Athena barge at the time of the accident. He is seeking unspecified sums as a result of the alleged negligence of defendants and injuries incurred following the October 12, 2006 accident. By mutual agreement of the parties on October 19, 2007, we are not required to respond until receipt of further notification from the plaintiff.

Due to the early stages of certain of the above 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 affect on our financial condition or results of operations.

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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. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

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PART II

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

Through February 27, 2006, our common stock was traded on the NASD OTC Bulletin Board under the symbol GPOR.OB. Since February 28, 2006, our common stock has been quoted on The NASDAQ National Market and since July 14, 2006, our common stock has been quoted on The NASDAQ Global Select Market, in each instance 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**
2006		
First Quarter	$ 16.00	$ 10.00
Second Quarter	15.89	9.90
Third Quarter	13.64	9.82
Fourth Quarter	14.11	9.95
2007		
First Quarter	13.89	10.82
Second Quarter	21.34	12.86
Third Quarter	23.70	15.36
Fourth Quarter	25.62	16.60
2008		
First Quarter (through February 29, 2008)	19.41	13.49

On March 3, 2008, the last reported sale price of our common stock on The NASDAQ Global Select Market was $14.11. The above quotations for the periods prior to February 28, 2006 reflect inter-dealer prices, without retail mark-up, markdown or commissions and may not represent actual transactions.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Holders of Record

At the close of business on March 3, 2008, there were 361 stockholders of record holding 42,550,031 shares of our outstanding common stock. There were approximately 8,091 beneficial owners of our common stock as of March 3, 2008.

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 prohibits 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, 2007, December 31, 2006 and December 31, 2005 and the selected consolidated balance sheet data at December 31, 2007 and December 31, 2006 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, 2004 and December 31, 2003 and the selected consolidated balance sheet data at December 31, 2005, December 31, 2004 and December 31, 2003 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,				
	2007	2006	2005	2004	2003
Selected Consolidated Statements of Operations Data:					
Revenues	$ 105,838,000	$ 60,390,000	$ 27,559,000	$ 23,190,000	$ 15,947,000
Costs and expenses:					
Lease operating expenses	16,670,000	10,670,000	7,654,000	6,586,000	5,886,000
Production taxes	12,667,000	7,366,000	3,622,000	2,629,000	1,882,000
Depreciation, depletion and amortization	29,681,000	12,652,000	4,789,000	4,952,000	4,637,000
General and administrative	5,802,000	3,251,000	1,561,000	2,107,000	1,843,000
Accretion expense	554,000	596,000	516,000	490,000	393,000
	65,374,000	34,535,000	18,142,000	16,764,000	14,641,000
Income from Operations	40,464,000	25,855,000	9,417,000	6,426,000	1,306,000
Other (Income) Expense:					
Interest expense	3,091,000	1,956,000	250,000	246,000	112,000
Interest expense preferred stock			272,000	1,949,000	875,000
Business interruption insurance recoveries		(3,601,000)	(1,710,000)		
Interest income	(523,000)	(308,000)	(290,000)	(73,000)	(30,000)
	2,568,000	(1,953,000)	(1,478,000)	2,122,000	957,000
Income before Income Taxes and Effect of Change in Accounting Principle	37,896,000	27,808,000	10,895,000	4,304,000	349,000
Income Tax Expense	121,000				
Net Income before Effect of Change in Accounting Principle	37,775,000	27,808,000	10,895,000	4,304,000	349,000
Cumulative effect of change in accounting principal					270,000
Net Income	37,775,000	27,808,000	10,895,000	4,304,000	619,000
Less: Preferred stock dividends					(838,000)
Net Income (Loss) Available to Common Stockholders	$ 37,775,000	$ 27,808,000	$ 10,895,000	$ 4,304,000	$ (219,000)
Net Income (Loss) Per Common Share Basic:					
Per common share before effect of change in accounting principle	$ 1.03	$ 0.85	$ 0.36	$ 0.31	$ (0.05)

Effect per common share of change in accounting principle										0.03
	$	1.03	$	0.85	$	0.36	$	0.31	$	(0.02)
Net Income (Loss) Per Common Share Diluted:										
Per common share before effect of change in accounting principle	$	1.01	$	0.82	$	0.34	$	0.28	$	(0.05)
Effect per common share of change in accounting principle										0.03
	$	1.01	$	0.82	$	0.34	$	0.28	$	(0.02)

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	At Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
Selected Consolidated Balance Sheet Data:					
Total assets	$ 419,137,000	$ 195,151,000	$ 111,820,000	$ 78,150,000	$ 58,980,000
Total debt, including current maturity	$ 66,533,000	$ 37,691,000	$ 10,200,000	$ 3,404,000	$ 2,318,000
Total liabilities	$ 115,015,000	$ 71,342,000	$ 27,493,000	$ 29,053,000	$ 25,832,000
Stockholders equity	$ 304,122,000	$ 123,809,000	$ 84,327,000	$ 49,097,000	$ 33,148,000

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

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

Overview

We are an independent oil and natural gas exploration and production company with our principal producing properties located along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields. We have also recently acquired strategic assets 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.

2007 Highlights

- Oil and natural gas revenues increased $45.9 million to $106.1 million for the year ended December 31, 2007 from $60.2 million for 2006.

- Net income increased 36% to $37.8 million for the year ended December 31, 2007 from $27.8 million for 2006.

- Production increased 67% to 1,637,000 BOE for the year ended December 31, 2007 from 983,000 BOE for 2006.

- We received net proceeds of approximately $138.3 million from sales of our common stock in underwritten public offerings completed in February 2007, May 2007, July 2007 and December 2007, after deducting the underwriting discount and offering expenses. These net proceeds were used to pay down existing debt under our credit facility and fund substantially all of the purchase price for the acquisition of certain strategic assets in West Texas in the Permian Basin discussed in more detail below.

- On December 20, 2007, we completed an acquisition of strategic assets in West Texas in the Permian Basin for approximately $85 million, effective as of November 1, 2007. In this transaction we acquired 4,100 net acres with production of approximately 800 net BOE a day from 32 gross wells, predominately from the Wolfcamp formation. Existing production is approximately 64% oil, 23% natural gas liquids and 13% natural gas. We have identified 178 gross future development drilling locations. We expect 17 to 22 net wells to be drilled on this acreage in 2008. The wells are expected to be drilled to approximately 10,200 feet at an estimated average gross completed well cost of $1.7 million. We funded this transaction predominately through a 4.5 million common share offering, which closed on December 12, 2007. Operations from these properties were included in our results of operations for 2007 only from the closing date of December 21, 2007 through December 31, 2007.

- During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly Oil Sands ULC, a Canadian unlimited liability company holding leases in the Athabasca region located in northern Alberta Province, Canada near Fort McMurray near other oil sands development projects. As of December 31, 2007, our net investment in Grizzly was approximately $27.8 million. As of December 31, 2007, Grizzly had approximately 511,000 acres under lease. Grizzly drilled 62 core holes during the 2006/2007 winter delineation drilling season and tested three separate lease blocks with four

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drilling rigs. Core hole samples have been collected and sent to a lab to assess the quantity and thickness of the bitumen in place on our acreage. Future plans currently include acquiring additional leases, drilling approximately 55 to 60 additional core holes and a seismic program during the 2007/2008 winter drilling season, and initial planning for construction of a 10,000 barrel per day SAGD facility as soon as 2008, which could lead to initial production in 2011. Estimated gross capital expenditures for a comparable production facility are approximately $325 million.

During 2007, we drilled 38 wells and recompleted 62 wells. Of our 38 new wells drilled, 32 were completed as producing wells and six were non-productive.

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 $37,278,000 at December 31, 2007 and $1,459,000 at December 31, 2006. 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 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, 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. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A future decline in oil and gas prices may result in an impairment of oil and gas properties.

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

We account for abandonment and restoration liabilities under Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* SFAS No. 143, 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.

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Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management s opinion, it is more likely than not that some portion will not be realized. At December 31, 2007, a valuation allowance of $9,750,000 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 SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, 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 SFAS 133, 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 2007, we entered into 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, we 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 costs. In addition, we have entered into agreements to sell 3,500 barrels of production per day for the month of January through May 2008 at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, we have 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, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $81.37 per barrel before transportation costs. For August 2008, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $82.44 per barrel before transportation costs. For the periods of September 2008 through December 2008, we have entered into forward sales contracts for the sale of 3,000 barrels of production per day in each such period at weighted average daily prices of $82.20 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 60% of our estimated production for January through December 2008. For the period of January through December 2009, we entered into agreements to sell 2,500 barrels of production per day at a weighted average daily price of

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$84.62 per barrel before transportation costs. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production.

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:

	2007	2006	2005
Production Volumes:			
Oil (MBbls)	1,501	870	517
Gas (MMcf)	816	677	575
Oil Equivalents (Mboe)	1,637	983	613
Average Prices:			
Oil (per Bbl)	$ 66.71(1)	$ 64.43(1)	$ 46.39(1)
Gas (per Mcf)	$ 7.40	$ 6.20	$ 5.98
Oil Equivalents (per Mboe)	$ 64.86	$ 61.30	$ 44.75
Production Costs:			
Average Production Costs (per Boe)	$ 10.18(2)	$ 10.86(2)	$ 12.49(2)
Average Production Taxes (per Boe)	$ 7.74	$ 7.50	$ 5.91
Total Production Costs (per Boe)	$ 17.92	$ 18.36	$ 18.40

(1) Includes fixed contract prices of:

January June 2005	$ 33.10
July December 2005	$ 39.70
January December 2006	$ 64.05
June December 2007	$ 66.10

Excluding the 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 represents approximately 43% of our total oil sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2006 would have been $65.56 per barrel and $62.30 per barrel of oil equivalent. The total volume hedged for 2006 represents approximately 62% of our total oil sales volumes for the year. Excluding the effect of the fixed price contracts, the average oil price for 2005 would have been $56.17 per barrel and $52.99 per barrel of oil equivalent. Also includes financial hedge contracts with an average mark-to-market value of approximately $50,000 per month for the months of July-December 2005 and approximately $82,000 per month for the months of January-December 2006.

(2) Does not include production taxes.

From 2006 to 2007, our net oil production increased 73% from 869,728 barrels to 1,500,818 barrels due to our continued drilling activity. From 2005 to 2006, our oil production increased 68% to 869,728 barrels due to our continued drilling activity and also to a loss of production during the fourth quarter 2005 as a result of the damage caused to our facilities from Hurricane Rita in September 2005. We currently estimate that our 2008 production will be between 1,900,000 and 2,100,000 BOE with production increasing during the year.

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Comparison of the Years Ended December 31, 2007 and December 31, 2006

We reported net income of $37,775,000 for the year ended December 31, 2007, compared to $27,808,000 for the year ended December 31, 2006. This 36% increase in net income was due primarily to (1) a 67% increase in net production to 1,636,902 BOE for the year ended December 31, 2007 from 982,531 BOE for 2006 as a result of our continued drilling activity and (2) a 6% increase in the average BOE oil price received to $64.86 per barrel for the year ended December 31, 2007 from $61.30 per barrel for 2006. Although we closed the acquisition of the assets in the Permian Basin in West Texas on December 20, 2007, effective as of November 1, 2007, under GAAP only the oil and gas activities for the days subsequent to the closing date, which in this case were from December 21 through December 31, 2007, can be included in our 2007 oil and gas activities. As a result, activities related to these new assets had little impact on our results of operations for the year ended December 31, 2007.

Oil and Gas Revenues. For the year ended December 31, 2007, we reported oil and gas revenues of $106,163,000, compared to oil and gas revenues of $60,232,000 during 2006. This $45,931,000, or 76%, increase in revenues is primarily attributable to a 67% increase in net production to 1,636,902 BOE for the year ended December 31, 2007 from 982,531 BOE for the year ended December 31, 2006. Production in the first half of 2006 was negatively impacted by the damage caused by Hurricane Rita, as production from our wells at WCBB was not fully restored until later in 2006.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2007 and 2006:

	Year Ended December 31,	
	2007	**2006**
Oil production volumes (MBbls)	1,501	870
Gas production volumes (MMcf)	816	677
Oil equivalents (Mboe)	1,637	983
Average oil price (per Bbl)	$ 66.71	$ 64.43
Average gas price (per Mcf)	$ 7.40	$ 6.20
Oil equivalents (per Boe)	$ 64.86	$ 61.30

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $16,670,000 for the year ended December 31, 2007 from $10,670,000 for 2006. Since our WCBB facilities continued to be shut in until late in the first quarter of 2006 due to the impact of Hurricane Rita some of the costs that would have normally been associated with our lease operating expenses were instead spent on ongoing restoration and repair activities during the year ended December 31, 2006. In addition, lease operating expenses for the year ended December 31, 2007 increased due to increased labor requirements associated with a ramp up in overall activity in both fields, increases in rates paid for labor and other services, increases in the cost of oil-based supplies, non-recurring repairs including repairs to compressors, and increases in property taxes in both fields as a result of the on-going capital programs. These increases were partially offset by a reduction in lease operating expenses attributable to our interest in the Marquiss field which we sold during February 2007.

Production Taxes. Production taxes increased to $12,667,000 for the year ended December 31, 2007 from $7,366,000 for 2006. This increase was directly related to a 76% increase in oil and gas revenues as a result of the increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $29,681,000 for the year ended December 31, 2007, and consisted of $29,220,000 in depletion on oil and natural gas properties and $461,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $12,652,000 for the year ended December 31, 2006. This increase was due primarily to an increase in our production, an increase in our oil and natural gas property costs associated with our 2006 and 2007 drilling programs and an increase in our future development costs.

General and Administrative Expenses. Net general and administrative expenses increased to $5,802,000 for 2007 from $3,251,000 for 2006. This increase was due primarily to increases in payroll costs and related benefits as a result of increases in the total number of employees. In addition, this increase also resulted from $310,000 of costs associated with the implementation of Section 404 of the Sarbanes-Oxley Act, an increase of $300,000 in franchise taxes, an increase of $220,000 for the services provided by our external reserve engineers, an increase of $100,000 in our business and D&O insurance costs and an increase of $95,000 for expenses associated with SFAS No. 123(R), *Share Based Payment.* These increases were partially offset by an increase in the amount of capitalized general and administrative expenses and a decrease in legal expenses and corporate fees.

Accretion Expense. Accretion expense decreased to $554,000 for 2007 from $596,000 for 2006. Although there was a larger obligation at the beginning of 2007 than there was at the beginning of 2006 resulting from the addition of future abandonment obligations on new wells drilled during 2006, the effect of the increase on the larger obligations was more than offset by the effect of the sale of the Marquiss properties in February 2007.

Interest Expense. Interest expense increased to $3,091,000 for 2007 from $1,956,000 for 2006 due to an increase in average debt outstanding. Total weighted debt outstanding under our facilities with Bank of America was $33.2 million for the year ended December 31, 2007, as compared to $18.8 million for 2006. In addition, during July 2006 we entered into a new $5.0 million term loan agreement with Bank of America. As a result, during the year ended December 31, 2007, we recognized a full year of interest related to the term loan in the amount of $382,000 as compared to only $115,000 for 2006.

Income Taxes. As of December 31, 2007, we had a net operating loss carry forward of approximately $93 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, 2007, a valuation allowance of $9.8 million had been provided for deferred tax assets. We had only a slight 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 we have substantial net operating loss carryforwards, these cannot be used to offset alternative minimum tax liabilities.

Comparison of the Years Ended December 31, 2006 and December 31, 2005

We reported net income of $27,808,000 for the year ended December 31, 2006, compared to $10,895,000 for the year ended December 31, 2005. This 155% increase in net income was due primarily to (1) a 60% increase in net production to 982,531 BOE for the year ended December 31, 2006 from 612,840 BOE for 2005, (2) a 39% increase in the average oil price received to $64.43 per barrel for the year ended December 31, 2006 from $46.39 per barrel for 2005 and (3) business interruption insurance recoveries of $3,601,000 due to Hurricane Rita.

Oil and Gas Revenues. For the year ended December 31, 2006, we reported oil and gas revenues of $60,232,000, compared to oil and gas revenues of $27,423,000 during 2005. This 120% increase in revenues is mainly attributable to a 60% increase in net production to 982,531 BOE for the year ended December 31, 2006 from 612,840 BOE for 2005 and a 39% increase in the average oil price received to $64.43 per barrel for the year ended December 31, 2006 from $46.39 per barrel for 2005. This increase in oil and natural gas production was the result of production from our 2006 drilling program and restoration of fields and facilities for which production was curtailed due to Hurricane Rita. Production in 2005 and 2006 was adversely affected by the damage caused by Hurricane Rita. In addition, production in 2006 was adversely affected by the accident in our field on October 12, 2006, which shut in our facilities from that date through early December 2006.

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The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2006 and December 31, 2005:

	Year Ended December 31, 2006	2005
Oil production volumes (MBbls)	870	517
Gas production volumes (MMcf)	677	575
Oil equivalents (Mboe)	983	613
Average oil price (per Bbl)	$ 64.43	$ 46.39
Average gas price (per Mcf)	$ 6.20	$ 5.98
Oil equivalents (per Boe)	$ 61.30	$ 44.75

Lease Operating Expenses. Lease operating expenses not including production taxes increased to $10,670,000 for 2006 from $7,654,000 for 2005. This increase was mainly due to increases in insurance costs, $972,000 in one time non-recurring repairs to the WCBB gas sales pipeline related to the tug boat accident that occurred in October 2006 and the increases in the general costs of labor and supplies in our operating area along the Louisiana Gulf Coast.

Production Taxes. Production taxes increased to $7,366,000 for 2006 from $3,622,000 for 2005. This increase was directly related to a 120% increase in oil and gas revenues as a result of the 37% improvement in the price received per barrel oil equivalent and a 60% increase in production for 2006 compared to 2005.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased to $12,652,000 for the year ended December 31, 2006, and consisted of $12,259,000 in depletion on oil and natural gas properties and $393,000 in depreciation of other property and equipment. This compares to total depreciation, depletion and amortization expense of $4,789,000 for the year ended December 31, 2005. This increase was due primarily to an increase in our oil and natural gas property costs associated with our 2006 drilling program and an increase in our oil and gas production for the period.

General and Administrative Expenses. Net general and administrative expenses increased to $3,251,000 for 2006 from $1,561,000 for 2005. This increase was due primarily to the $1,063,000 effect of the implementation of SFAS No. 123(R), Share Based Payment (less $276,000 capitalized for personnel directly related to our exploration and development activities), a $250,000 increase in corporate fees relating to being a NASDAQ listed company, and general increases in the payroll costs and related benefits as a result of the increased number of employees. These increases were partially offset by increases in general administrative reimbursements from our affiliates.

Accretion Expense. Accretion expense increased $80,000 to $596,000 for 2006 from $516,000 for 2005, due to a larger obligation at the beginning of 2006 compared to the beginning of 2005, resulting from the addition of future abandonment obligations on new wells drilled during 2005.

Interest Expense. Ordinary interest expense increased to $1,956,000 for 2006 from $250,000 for 2005 due to an increase in average debt outstanding. At December 31, 2006, total debt outstanding under our facility with Bank of America was $34,800,000. At December 31, 2005, $7,000,000 was outstanding under this facility.

Interest Expense Preferred Stock. During the year ended December 31, 2005, we incurred interest expense on preferred stock classified as a liability under SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. During 2005, we redeemed all of the remaining outstanding shares of our Series A preferred stock. As a result, we incurred no interest expense relating to preferred stock during 2006 as compared to $272,000 in interest expense incurred during 2005.

Income Taxes. As of December 31, 2006, we had a net operating loss carry forward of approximately $95.9 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

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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, 2006, a valuation allowance of $25.5 million had been provided for our entire net deferred tax asset. We had no income tax expense due to a change in the valuation allowance for deferred income taxes for the year ended December 31, 2006.

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. During the year ended December 31, 2006, recoveries under our insurance coverages also provided a significant source of funds due to damage from Hurricane Rita in September 2005 and the resulting interruption of our business during the fourth quarter of 2005 and the six months ended June 2006.

Net cash flow provided by operating activities was $68,902,000 for 2007, as compared to net cash flow provided by operating activities of $39,523,000 for 2006. This increase was primarily the result of an increase in cash receipts from our oil and gas purchasers due to a 67% increase in net production, partially offset by increases in cash paid for lease operating expenses and production taxes.

Net cash flow provided by operating activities was $15,200,000 for 2005, as compared to $39,523,000 for 2006. The increase of $24,323,000 in 2006 was primarily the result of an increase in cash receipts from our oil and gas purchasers due to higher prices received for oil production and a 60% 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 2007 was $240,733,000, as compared to $73,876,000 for 2006. During the year ended December 31, 2007, we spent $220,044,000 in additions to oil and natural gas properties, of which $96,113,000 was spent on our 2007 drilling program, $85,230,000 was spent on our acquisition of certain strategic assets in Upton County, Texas in the Permian Basin, $12,319,000 was spent on expenses attributable to the wells drilled during 2006, $9,467,000 was spent on our new Hackberry barge facilities, $2,834,000 was spent on additions to oil and natural gas properties due to Hurricane Rita, with the remainder attributable mainly to facility enhancement and capitalized general and administrative expenses. During the year ended December 31, 2007, we made investments of $17,316,000 in Grizzly. During the year ended December 31, 2007, we used cash from operations, proceeds from the sale of 8,547,500 shares of our common stock and borrowings under our credit facility to fund our investing activities.

Net cash used in investing activities for 2005 was $36,703,000, as compared to $73,876,000 for 2006. During the year ended December 31, 2006, we spent $62,403,000 in additions to oil and natural gas properties, of which $40,040,000 was spent on our 2006 drilling program, $5,175,000 was attributable to the wells drilled during 2005, $2,179,000 was spent on additions to oil and natural gas properties due to the hurricane net of insurance proceeds, $5,517,000 was spent on new compressors for WCBB, with the remainder attributable mainly to capitalized general and administrative expenses and recompletions. In addition, during the year ended December 31, 2006, we made investments of $964,000 in Tatex Thailand II, $1,416,000 in Windsor Bakken LLC, and $8,493,000 in Grizzly Oil Sands ULC. We used cash from operations, proceeds from the sale of company common stock, insurance recoveries and borrowings under our credit facility to fund our investing activities in 2006.

Net cash provided by financing activities for 2007 was $167,968,000, as compared to $38,861,000 for 2006. 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,

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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. The 2006 amount provided by financing activities is attributable to draws of $33,300,000 on our credit facility with Bank of America and proceeds before offering costs of $10,451,000 from the issuance of common stock in our May 2006 underwritten public offering and $1,276,000 from the exercise of stock options.

Net cash provided by financing activities for 2005 was $16,080,000, which amount is primarily attributable to aggregate net cash proceeds of approximately $23,600,000 from (1) the issuance of common stock in two private placements and (2) the exercise of the outstanding warrants and net borrowings of $6,796,000, partially offset by the approximately $14,292,000 used to redeem all 14,202 outstanding shares of our Series A preferred stock.

Issuance of Equity. In January 2007, we sold 1,150,000 shares of our common stock in an underwritten offering at an offering price to the public of $11.92 per share. In connection with the offering, we granted the underwriter an option to purchase up to an additional 172,500 shares of our common stock to cover any over-allotments, which the underwriter exercised in full. We 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. These net proceeds were used to pay down outstanding debt under our credit facility.

In May 2007, we sold 1,500,000 shares of our common stock in an underwritten offering at an offering price to the public of $16.00 per share. In connection with the offering, we granted the underwriter an option to purchase up to an additional 225,000 shares of our common stock to cover any over-allotments, which the underwriter exercised in full. We 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. These net proceeds were used to pay down outstanding debt under our credit facility.

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

In December 2007, we sold 4,500,000 shares of our common stock in an underwritten offering at an offering price to the public of $17.50 per share. We received the net proceeds of approximately $75.6 million from our sale of these shares on December 12, 2007 after deducting underwriting discounts and commissions and before offering expenses. We used the net proceeds from this offering to fund substantially all of the purchase price for our interest in the acquisition of certain strategic assets in Upton County, Texas in the Permian Basin. In connection with this offering, a selling stockholder granted the underwriters an option to purchase an additional 675,000 shares of our common stock at a price of $16.80 per share solely to cover any over-allotments, which underwriters exercised in full. We did not receive any proceeds from the sale of shares of our common stock by the selling stockholder.

Credit Facility. On March 11, 2005, we entered into a three-year secured reducing credit agreement, as amended, providing for a revolving credit facility with Bank of America, N.A. 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 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 million and the Eurodollar interest rate, which we can elect to use at our option, reduced by 0.75%. In addition, the maturity date was extended from March 31, 2009 to March 31, 2010. We agreed to pay a borrowing base increase fee of 0.50% of any increase of the borrowing base over the highest borrowing base previously in effect, payable on the day such increased borrowing base becomes effective. We make quarterly interest payments on amounts borrowed under the facility, which amounts bear interest at Bank of America prime plus 0.25% (7.5 % at December 31, 2007). Our obligations under the credit facility are collateralized by a lien on substantially all of our Louisiana and West Texas oil and gas assets.

The credit facility 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, 2007. As of December 31, 2007, approximately $59.5 million was outstanding under this facility, which is included in long-term debt, net of current maturities on the accompanying consolidated balance sheet. We have used the proceeds of our borrowings under the credit facility for the exploration of our oil and natural gas properties and other capital expenditures, acquisition opportunities, replacement of facilities and equipment due to Hurricane Rita 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 (7.25 % at December 31, 2007). 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, 2007, approximately $4.3 million was outstanding under this agreement, of which $714,000 and $3,580,000 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. 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 Oil Sands ULC and fund Grizzly s delineation drilling program and for acquisitions, primarily our recently completed transaction in the Permian Basin. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties and (2) explore other acquisition opportunities. We have upgraded our infrastructure and our existing facilities 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 will also be required to pay 50% of all drilling costs for future drilling activity on such properties.

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In our December 31, 2007 reserve reports, 72% 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 111 drilling locations at WCBB. The drilling schedule used in our December 31, 2007 reserve report anticipates that all of those wells will be drilled by 2019. From January 1, 2008 through March 1, 2008, we drilled two wells and recompleted 14 existing wells at our WCBB field. We currently intend to spend a total of approximately $21 to $23 million for drilling, recompletion and other activities in our WCBB field during 2008.

In our East Hackberry field, from January 1, 2008 through March 1, 2008, we drilled one well and recompleted three wells. We intend to drill three to five additional land wells and recomplete one additional well during 2008. Total capital expenditures for our East Hackberry field during 2008 are estimated at $17 to $19 million.

During the third quarter of 2006, we purchased a 24.9999% interest in Grizzly. As of December 31, 2007, our net investment in Grizzly was approximately $27.8 million. Capital requirements in 2008 for this project are now estimated to be approximately $8 to $10 million, primarily for the expenses associated with our 2007/2008 55 to 60 well core hole drilling program, a seismic program and additional lease acquisitions.

Capital expenditures in 2008 relating to our interest in Thailand are expected to be approximately $1.0 million, which we believe will be mostly offset from our share of production from the Phu Horm field.

Capital expenditures in 2008 relating to our interest in the Bakken Shale in the Williston Basin are expected to be approximately $10.0 million, which we believe will be partially offset from our share of production from the field.

We anticipate that our capital requirements for our properties in the Permian Basin in West Texas purchased on December 20, 2007 will be approximately $35 million during 2008. We have identified 178 gross future development drilling locations. We currently expect that approximately 17 to 22 net wells will be drilled on this acreage in 2008.

Our total capital expenditures for 2008 are currently estimated to be $95 million. We believe that our cash on hand, cash flow from operations and borrowings under our credit facility will be sufficient to meet our normal recurring operating needs, debt service obligations, and our WCBB, Hackberry, Bakken, and Permian Basin 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 will 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

To mitigate the effects of commodity price fluctuations, during 2007, we entered into 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, we 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 costs. In addition, we have entered into agreements to sell 3,500 barrels of production per day for the month of January through May 2008 at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, we have agreements to sell 3,500

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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, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $81.37 per barrel before transportation costs. For August 2008, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $82.44 per barrel before transportation costs. For the periods of September 2008 through December 2008, we have entered into forward sales contracts for the sale of 3,000 barrels of production per day in each such period at weighted average daily prices of $82.20 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 60% of our estimated production for January through December 2008. For the period of January through December 2009, we entered into agreements to sell 2,500 barrels of production per day at a weighted average daily price of $84.62 per barrel before transportation costs. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production. 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 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2007, the plugging and abandonment trust totaled approximately $3,104,000, including interest received during 2007 of approximately $126,000. At December 31, 2007, we had plugged 243 wells at WCBB since we began our plugging program in 1997. An additional ten wells were plugged in January 2008, which management believes fulfills our minimum plugging obligation through March 31, 2008.

Contractual and Commercial Obligations

	Payment due by period				
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Short-term and long-term debt	$ 66,533,000	$ 808,000	$ 64,288,000	$ 1,437,000	$
Asset retirement obligations	8,634,000	480,000	1,228,000	779,000	6,147,000
Total	$ 75,167,000	$ 1,288,000	$ 65,516,000	$ 2,216,000	$ 6,147,000

New Accounting Pronouncements

We adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*, as of January 1, 2007. The adoption of this Interpretation had no effect on our consolidated financial statements. We are subject to U.S. federal income tax as well as income tax of multiple state jurisdictions. Our 1996 2006 U.S. federal and state income tax returns remain open to examination by the Internal Revenue Service. We are continuing our practice of recognizing interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively.

SFAS 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. SFAS No. 157 addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption permitted. However, in February, 2008, the FASB issued FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157* which delays

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the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This FSP partially defers the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of this FSP. We are currently assessing the impact, if any, of the adoption of SFAS 157.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits companies to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing companies with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which we elect the fair value measurement option would be reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. We are currently assessing the impact, if any, of the adoption of SFAS No. 159.

SFAS No. 141(R)

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) 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. SFAS No. 141(R) also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008. We are currently assessing the impact, if any, the adoption of SFAS No. 141(R) may have on any future acquisitions.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51.* SFAS 160 requires that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS 160 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 are currently assessing the impact, if any, of the adoption of SFAS 160.

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.

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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, over the last four years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.83 per barrel, or bbl, in January 2004 to a high of $102.20 per bbl on March 6, 2008. The Henry Hub spot market price of natural gas has ranged from a low of $4.20 per million British thermal units, or MMBtu, in October 2006 to a high of $13.93 per MMBtu in October 2005. On December 31, 2007, the West Texas Intermediate posted price for crude oil was $92.50 per bbl and the Henry Hub spot market price of natural gas was $6.80 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 2007, we entered into 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, we 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 costs. In addition, we have entered into agreements to sell 3,500 barrels of production per day for the months of January through May 2008 at a weighted average daily price of $70.29 per barrel before transportation costs. For the month of June 2008, we have 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, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $81.37 per barrel before transportation costs. For August 2008, we have agreements to sell 3,000 barrels of production per day at a weighted average daily price of $82.44 per barrel before transportation costs. For the periods of September 2008 through December 2008, we have entered into forward sales contracts for the sale of 3,000 barrels of production per day in each such period at weighted average daily prices of $82.20 per barrel before transportation costs. Under these agreements we have committed to deliver approximately 60% of our estimated production for January through December 2008. For the period of January through December 2009, we entered into agreements to sell 2,500 barrels of production per day at a weighted average daily price of $84.62 per barrel before transportation costs. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These contracts require physical delivery of production quantities and are exempted from the provisions of SFAS 133 as normal sales of production. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

Our credit facility and term loan 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 bear interest at Bank of America prime plus 0.25% (7.5 % at December 31, 2007). Borrowings under our term loan with Bank of America bear interest at Bank of America prime (7.25 % at December 31, 2007). Based on the current debt structure, a 1% increase in interest rates would increase interest expense by approximately $638,000 per year, based on an aggregate of $63.8 million outstanding under our credit facilities as of December 31, 2007. As of December 31, 2007, 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.

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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, 2007, 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 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, 2007, our disclosure controls and procedures are effective.

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

Management s Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of 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, 2007.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2007 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2007, as stated in their accompanying report.

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

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Gulfport Energy Corporation:

We have audited internal control over financial reporting of Gulfport Energy Corporation and Subsidiaries (the Company) as of December 31, 2007, 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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 the Company as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2007 and our report dated March 17, 2008 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 17, 2008

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information concerning Item 10 Directors, Executive Officers and Corporate Governance, see our definitive Information 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 Information 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 Information 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 Information 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 Information 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, FINANCIAL STATEMENTS AND 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	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).

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Exhibit Number	Description
10.4+	Employment Agreement, dated as of May 18, 1999 and effective as of June 1, 1999, by and between the Registrant 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	Credit Agreement, dated as of March 11, 2005, by and among the Company, each lender from time to time party thereto and Bank of America, N.A., as agent (incorporated by reference to Exhibit 10.9 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
10.6	Second Amendment to Credit Agreement, dated as of July 19, 2007, between the Company and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
10.7	Note dated July 19, 2007 issued by the Company for the benefit of Bank of America, N.A. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 19, 2007).
10.8	Third Amendment to Credit Agreement, dated as of December 20, 2007, between the Company, Bank of America, N.A., as a lender and administrative agent and such other lenders from time to time party hereto (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2007).
10.9	Note dated December 20, 2007 issued by the Company for the benefit of Bank of America, N.A. (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2007).
10.10	Administrative Services Agreement, effective as of April 1, 2005, by and between Bronco Drilling Company, Inc. and Gulfport Energy Corporation (incorporated by reference from Exhibit 10.1 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on August 15, 2005).
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.

* 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 17, 2008

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 17, 2008	By:	/s/ JAMES D. PALM **James D. Palm** **Chief Executive Officer and Director** **(Principal Executive Officer)**
Date: March 17, 2008	By:	/s/ MIKE LIDDELL **Mike Liddell** **Chairman of the Board and Director**
Date: March 17, 2008	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **Vice President and Chief Financial Officer** **(Principal Financial and Accounting Officer)**
Date: March 17, 2008	By:	/s/ DONALD DILLINGHAM **Donald Dillingham** **Director**
Date: March 17, 2008	By:	/s/ DAVID L. HOUSTON **David L. Houston** **Director**

Date: March 17, 2008	By:	/s/	SCOTT E. STRELLER
			Scott E. Streller
			Director

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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, 2007 and 2006, and the related consolidated statements of operations, stockholders equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment, on a modified prospective basis effective January 1, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2007, 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 17, 2008 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

March 17, 2008

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GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 2,764,000	$ 6,627,000
Accounts receivable oil and gas	10,510,000	7,585,000
Insurance settlement receivables		541,000
Accounts receivable related parties	2,208,000	4,202,000
Prepaid expenses and other current assets	1,346,000	972,000
Total current assets	16,828,000	19,927,000
Property and equipment:		
Oil and natural gas properties, full-cost accounting,		
$37,278,000 and $1,459,000 excluded from amortization in 2007 and 2006, respectively	484,487,000	250,838,000
Other property and equipment	7,108,000	6,651,000
Accumulated depletion, depreciation and amortization	(129,496,000)	(99,815,000)
Property and equipment, net	362,099,000	157,674,000
Other assets:		
Equity investments	33,822,000	14,363,000
Other assets	6,388,000	3,187,000
Total other assets	40,210,000	17,550,000
Total assets	$ 419,137,000	$ 195,151,000
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 39,848,000	$ 24,793,000
Asset retirement obligation current	480,000	480,000
Current maturities of long-term debt	808,000	835,000
Total current liabilities	41,136,000	26,108,000
Asset retirement obligation long-term	8,154,000	8,378,000
Long-term debt, net of current maturities	65,725,000	36,856,000
Total liabilities	115,015,000	71,342,000
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, 55,000,000 authorized, 42,453,587 issued and outstanding in 2007 and 33,659,759 in 2006	424,000	337,000
Paid-in capital	271,807,000	131,610,000
Accumulated other comprehensive income	2,254,000	
Retained earnings (accumulated deficit)	29,637,000	(8,138,000)
Total stockholders equity	304,122,000	123,809,000
Total liabilities and stockholders equity	$ 419,137,000	$ 195,151,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	**2006**	**2005**
Revenues:			
Oil and condensate sales	$ 100,120,000	$ 56,038,000	$ 23,986,000
Gas sales	6,043,000	4,194,000	3,437,000
Other income (expense)	(325,000)	158,000	136,000
	105,838,000	60,390,000	27,559,000
Costs and expenses:			
Lease operating expenses	16,670,000	10,670,000	7,654,000
Production taxes	12,667,000	7,366,000	3,622,000
Depreciation, depletion and amortization	29,681,000	12,652,000	4,789,000
General and administrative	5,802,000	3,251,000	1,561,000
Accretion expense	554,000	596,000	516,000
	65,374,000	34,535,000	18,142,000
INCOME FROM OPERATIONS	40,464,000	25,855,000	9,417,000
OTHER (INCOME) EXPENSE:			
Interest expense	3,091,000	1,956,000	250,000
Interest expense preferred stock			272,000
Business interruption insurance recoveries		(3,601,000)	(1,710,000)
Interest income	(523,000)	(308,000)	(290,000)
	2,568,000	(1,953,000)	(1,478,000)
INCOME BEFORE INCOME TAXES	37,896,000	27,808,000	10,895,000
INCOME TAX EXPENSE	121,000		
NET INCOME	$ 37,775,000	$ 27,808,000	$ 10,895,000
NET INCOME PER COMMON SHARE:			
Basic	$ 1.03	$ 0.85	$ 0.36
Diluted	$ 1.01	$ 0.82	$ 0.34

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

	Common Stock						
	Shares	**Amount**	**Additional Paid-in Capital**	**Notes Receivable for Exercise of Options**	**Accumulated Other Comprehensive Income**	**Retained Earnings (Accumulated Deficit)**	**Total Stockholders Equity**
Balance at January 1, 2005	20,146,566	$ 201,000	$ 95,737,000	$	$	$ (46,841,000)	$ 49,097,000
Net income						10,895,000	10,895,000
Other Comprehensive Income:							
Deferred gain on settled contracts					114,000		114,000
Loss on hedging ineffectiveness					24,000		24,000
Unrealized gain on hedges					621,000		621,000
Total Comprehensive Income							11,654,000
Issuance of Common Stock	4,000,000	40,000	13,960,000				14,000,000
Issuance of Common Stock through exercise of warrants	7,958,470	80,000	9,390,000				9,470,000
Issuance of Common Stock through exercise of options	63,167	1,000	105,000	(105,000)			1,000
Repayment of Notes Receivable for Stock				105,000			105,000
Balance at December 31, 2005	32,168,203	322,000	119,192,000		759,000	(35,946,000)	84,327,000
Net income						27,808,000	27,808,000
Other Comprehensive Income:							
Deferred gain on settled contracts					(114,000)		(114,000)
Gain on hedging ineffectiveness					(24,000)		(24,000)
Reclassification adjustment on settled hedges					(621,000)		(621,000)
Total Comprehensive Income							27,049,000
Stock Compensation			1,063,000				1,063,000
Issuance of Common Stock in public offering, net of related expenses of $479,000	790,000	8,000	9,965,000				9,973,000
Issuance of Restricted Stock	21,981						
Issuance of Common Stock through exercise of Warrants	113,852	1,000	120,000				121,000
Issuance of Common Stock through exercise of Options	565,723	6,000	1,270,000				1,276,000
Balance at December 31, 2006	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

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007	2006	2005
Cash flows from operating activities:			
Net income	$ 37,775,000	$ 27,808,000	$ 10,895,000
Adjustments to reconcile net income to net cash provided by operating activities:			
Accretion of discount Asset Retirement Obligation	554,000	596,000	516,000
Interest expense preferred stock			272,000
Depletion, depreciation and amortization	29,681,000	12,652,000	4,789,000
Stock-based compensation expense	845,000	787,000	
Loss from equity investments	477,000	76,000	
Unrealized (gain) loss on hedge ineffectiveness		(24,000)	24,000
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(2,925,000)	(6,609,000)	2,584,000
Decrease (increase) in business interruption insurance settlement receivable		1,710,000	(1,710,000)
Decrease (increase) in accounts receivable related party	1,994,000	(832,000)	(2,347,000)
Increase in prepaid expenses	(374,000)	(490,000)	(270,000)
Decrease in deposits		107,000	
Increase in accounts payable and accrued liabilities	2,153,000	4,608,000	1,074,000
(Increase) decrease in deferred hedge gains		(114,000)	114,000
Settlement of asset retirement obligation	(1,278,000)	(752,000)	(741,000)
Net cash provided by operating activities	68,902,000	39,523,000	15,200,000
Cash flows from investing activities:			
Additions to cash held in escrow	(121,000)	(105,000)	(57,000)
Additions to deposits for oil and gas properties	(3,080,000)		
Additions to other property, plant and equipment	(457,000)	(495,000)	(467,000)
Additions to oil and gas properties	(220,044,000)	(62,403,000)	(31,995,000)
Proceeds from sale of oil and gas properties	500,000		70,000
Investment in Grizzly Oil Sands ULC	(17,316,000)	(8,493,000)	
Investment in Tatex Thailand II, LLC	(88,000)	(964,000)	(2,502,000)
Investment in Windsor Bakken, LLC	(127,000)	(1,416,000)	(1,752,000)
Net cash used in investing activities	(240,733,000)	(73,876,000)	(36,703,000)
Cash flows from financing activities:			
Principal payments on borrowings	(47,158,000)	(10,809,000)	(204,000)
Borrowings on line of credit	76,000,000	38,300,000	7,000,000
Redemption of Series A, Preferred Stock			(14,292,000)
Proceeds from issuance of common stock, net of offering costs of $740,000 and $479,000, and exercise of stock options	139,126,000	11,370,000	23,576,000
Net cash provided by financing activities	167,968,000	38,861,000	16,080,000
Net increase (decrease) in cash and cash equivalents	(3,863,000)	4,508,000	(5,423,000)
Cash and cash equivalents at beginning of period	6,627,000	2,119,000	7,542,000
Cash and cash equivalents at end of period	$ 2,764,000	$ 6,627,000	$ 2,119,000

Supplemental disclosure of cash flow information:						
Interest payments	$	3,341,000	$	1,956,000	$	250,000
Income tax payments	$	121,000	$		$	
Supplemental disclosure of non-cash transactions:						
Investment subscription payable	$	151,000	$		$	688,000
Capitalized stock based compensation	$	313,000	$	276,000	$	
Payment of Series A Preferred Stock dividends through issuance of Series A Preferred Stock	$		$		$	272,000
Asset retirement obligation capitalized	$	500,000	$	405,000	$	1,382,000

See accompanying notes to consolidated financial statements.

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GULFPORT ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2007, 2006 AND 2005

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation (Gulfport or the Company) is a domestic independent oil and gas exploration, development and production company with its principal properties located in the Louisiana Gulf Coast. Gulfport also recently acquired strategic assets 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. and Jaguar Resources LLC. 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 located in the southwestern part of the United States. The majority of its receivables are from two purchasers of the Company s oil and gas. 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, 2007 and December 31, 2006.

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, 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 to amortization consist of the cost of unproved leaseholds and totaled $37,278,000 and $1,459,000 at December 31, 2007 and December 31, 2006, respectively. These costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2007, 2006 AND 2005

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 Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143), 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 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.

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 7 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.

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 14.

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.

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DECEMBER 31, 2007, 2006 AND 2005

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, 2007 and 2006 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.

Accounting for Stock-Based Compensation

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standard No. 123(R), *Share-Based Payment* (SFAS No. 123(R)), using the modified prospective transition method. SFAS No. 123(R) 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. Under the modified prospective transition method, share-based awards granted or modified on or after January 1, 2006, are recognized as compensation expense over the applicable vesting period. Also, any previously granted awards that are not fully vested as of January 1, 2006 are recognized as compensation expense over the remaining vesting period. No retroactive or cumulative effect adjustments were required upon the Company s adoption of SFAS No. 123(R) (see Note 10). The shares of stock issued once the options are exercised will be from authorized but unissued common stock.

Prior to adopting SFAS No. 123(R), the Company accounted for its fixed-plan employee stock options using the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25), and related interpretations. This method required compensation expense to be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price.

If the Company had elected the fair value provisions of SFAS No. 123(R) and recognized compensation expense over the vesting period based on the fair value of the stock options granted as of their grant date, the Company s 2005 net income and net income per share would have differed from the amounts actually reported as shown in the following table.

	Year Ended December 31, 2005
Net income, as reported	$ 10,895,000
Stock-based employee compensation expense	248,000
Net income, pro forma	$ 10,647,000
Net income per share:	
As reported:	
Basic	$ 0.36
Diluted	$ 0.34

Pro forma:		
Basic	$	0.35
Diluted	$	0.33

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2007, 2006 AND 2005

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 (collectively price swap contracts). The Company follows the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities.* 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.

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 SFAS 133, changes in fair value are recognized in 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 had no derivative contracts at December 31, 2007 and 2006.

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 and the realization of future net operating loss carryforwards available as reductions of income tax expense.

Recent Accounting Pronouncements

The Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109,* as of January 1, 2007. The adoption of FIN 48 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 state jurisdictions. The Company s 1996-2006 U.S. federal and state income tax returns remain open to examination by tax authorities. As of December 31, 2007, the Company has no unrecognized tax benefits that would have a material impact on the effective tax 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, 2007, there is no interest or penalties associated with uncertain tax positions in the Company s consolidated financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with earlier adoption permitted. However, in

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DECEMBER 31, 2007, 2006 AND 2005

February, 2008, the FASB issued FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157* which delays the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This FSP partially defers the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of this FSP. The Company is currently assessing the impact, if any, of the adoption of SFAS 157.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits companies to choose to measure certain financial instruments and other items at fair value. The objective is to improve financial reporting by providing companies with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. Unrealized gains and losses on any items for which the Company elects the fair value measurement option would be reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The Company does not expect the adoption of SFAS No. 159 to have a material impact to its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS 141(R)), which replaces FASB Statement No. 141. SFAS 141(R) 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. SFAS No. 141(R) also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008. The Company is currently assessing the impact, if any, the adoption of SFAS No. 141(R) may have on any future acquisitions.