PETROHAWK ENERGY CORP
Form 10-K
March 14, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-K
ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2005
Commission file number 000-25717
PETROHAWK ENERGY CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**86-0876964**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

1100 Louisiana, Suite 4400, Houston, Texas 77002
(Address of principal executive offices including ZIP code)
(832) 204-2700
(Registrant s telephone number)
Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share	**NASDAQ National Market**

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer o Accelerated filer þ Non-accelerated filer o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No þ
The aggregate market value of Common Stock, par value $.001 per share (Common Stock), held by non-affiliates (based upon the closing sales price on the NASDAQ National Market on June 30, 2005), the last business day of registrant s most recently completed second fiscal quarter was approximately $418 million.
As of March 7, 2006, there were 83,264,331 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be filed on or before April 28, 2006 are incorporated by reference into Items 10, 11, 12, 13 and 14 of Part III of this report on Form 10-K.

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This report on Form 10-K and the documents or information incorporated by reference herein contain forward-looking statements within the meaning of the federal securities laws. These forward-looking statements include, among others, the following:

- our growth strategies;
- anticipated trends in our business;
- our future results of operations;
- our ability to make or integrate acquisitions;
- our liquidity and ability to finance our exploration, acquisition and development activities;
- our ability to successfully and economically explore for and develop oil and gas resources;
- market conditions in the oil and gas industry;
- the timing, cost and procedure for proposed acquisitions;
- the impact of government regulation;
- estimates regarding future net revenues from oil and natural gas reserves and the present value thereof;
- planned capital expenditures (including the amount and nature thereof);
- increases in oil and gas production;
- the number of wells we anticipate drilling in the future;
- estimates, plans and projections relating to acquired properties;
- the number of potential drilling locations; and
- our financial position, business strategy and other plans and objectives for future operations.

We identify forward-looking statements by use of terms such as may, will, expect, anticipate, estimate, hope, believe, predict, envision, intend, will, continue, potential, should, confident, could and similar w although some forward-looking statements may be expressed differently. You should be aware that our actual results could differ materially from those contained in the forward-looking statements. You should consider carefully the statements under the Risk Factors section of this report and other sections of this report which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements, and the following factors:

- the possibility that our acquisitions may involve unexpected costs;
- the volatility in commodity prices for oil and gas;
- the accuracy of internally estimated proved reserves;
- the presence or recoverability of estimated oil and gas reserves;

- the ability to replace oil and gas reserves;
- the availability and costs of drilling rigs and other oilfield services;
- environmental risks;
- exploration and development risks;
- competition;
- the inability to realize expected value from acquisitions;
- the ability of our management team to execute its plans to meet its goals;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we are doing business, that may be less favorable than expected; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our businesses, operations and pricing.

Forward-looking statements speak only as of the date of this report or the date of any document incorporated by reference in this report. Except to the extent required by applicable law or regulation, we do not undertake any obligation to update forward-looking statements to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

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PART I

ITEM 1. BUSINESS

Overview

Petrohawk Energy Corporation (Petrohawk or the Company), a Delaware corporation, is an independent oil and gas company engaged in the acquisition, development, production and exploration of oil and gas properties located in North America. We were formed in June 1997 as a Nevada corporation and were reincorporated in the state of Delaware in July 2004. Our properties are concentrated in the Permian Basin, East Texas/North Louisiana, Gulf Coast, South Texas, Anadarko and Arkoma regions. We have increased our proved reserves and production principally through acquisitions in conjunction with an active drilling program. Since November 2004, we have acquired approximately 535 billion cubic feet of natural gas equivalent (Bcfe) of proved reserves for approximately $1.2 billion, including the recently completed North Louisiana Acquisitions discussed below. During 2005, excluding acquisitions, we replaced approximately 149% of our production organically. Organic reserve additions were primarily driven by 3D seismic supported exploratory drilling in our core regions of South Texas and the Gulf Coast, as well as continuing evaluation of several fields in the Permian Basin. Fields that contributed significantly to the growth were the Lions (Goliad County, Texas); Waddell Ranch (Crane County, Texas); TXL (Ector County, Texas); Provident City (Colorado County, Texas); and Gueydan (Vermillion Parish, Louisiana). During 2005, we participated in the drilling of 146 wells, of which nine were dry holes, for a success rate of 94%.

At December 31, 2005, excluding the North Louisiana Acquisitions, our estimated total proved oil and gas reserves were approximately 437.3 Bcfe, consisting of 29.2 million barrels of oil (MMBbls) and 261.9 billion cubic feet (Bcf) of natural gas. Approximately 61% of our proved reserves were classified as proved developed.

We exited the year with an estimated daily production rate of approximately 130 million cubic feet equivalent (Mmcfe/d). This exit rate does not include an estimated 6 Mmcfe/d that remains shut-in from hurricane-related disruptions, and approximately 4 Mmcfe/d which is constrained in South Texas due to capacity issues. We currently expect shut-in production to return and capacity issues to be resolved during the first quarter or early second quarter of 2006.

We focus on maintaining a balanced, geographically diverse portfolio of long-lived, lower risk reserves along with shorter lived, higher margin reserves. We believe that this balanced reserve mix provides a diversified cash flow foundation to fund our development and exploration drilling program.

Recent Developments

We have recently completed several transactions:

Gulf of Mexico Divestiture

On February 3, 2006, we entered into a definitive agreement with Northstar GOM, LLC to sell substantially all of our Gulf of Mexico properties for $52.5 million in cash. These properties have estimated proved reserves as of December 31, 2005 of approximately 25 Bcfe, are approximately 70% gas, 59% proved developed and 27% operated. Current production is estimated to be approximately 10 Mmcfe/d. The transaction is expected to close by March 31, 2006.

The North Louisiana Acquisitions

On January 27, 2006, we completed the acquisition of all of the issued and outstanding common stock of Winwell Resources, Inc. (Winwell). The aggregate consideration paid was approximately $208 million in cash after certain closing adjustments. Also on January 27, 2006, we completed an acquisition of assets from Redley Company (Redley). The aggregate consideration paid was approximately $86 million in cash after certain closing adjustments. Through the Winwell and Redley transactions (referred to herein as the North Louisiana Acquisitions), we acquired gas properties in the Elm Grove and Caspiana fields in North Louisiana.

Reserve and production highlights of the North Louisiana Acquisitions include the following internal estimates:

- 106 Bcfe total proved reserves (98% gas, 29% proved developed) at December 31, 2005;
- 27,400 gross acres with 250 identified drilling locations;

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18-year reserve-to-production ratio based on average net daily production for December 2005 and internally estimated net proved reserves as of December 31, 2005;

Average 2006 projected production of 20 Mmcfe/d;

Production of approximately 16 Mmcfe/d for December 2005;

80% operated; and

Lease operating expense of approximately $0.55/Mmcfe projected for 2006.

We believe the properties present a significant, multi-year development opportunity primarily in the Cotton Valley and Hosston formations at depths of 6,500 to 10,000 feet. Successful wells in these fields generally produce for more than thirty years and have low operating costs. Our 2006 capital budget of $210 million includes approximately $35 million to accelerate development in these fields.

In conjunction with the closing of these transactions, we amended our senior revolving credit facility agreement and our second lien term loan facility. See the Contractual obligations section of Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations* for more details.

Mission Resources Corporation

We acquired Mission Resources Corporation (Mission) by merger on July 28, 2005. As a result of the Mission merger, we issued approximately 19.565 million shares of common stock and paid approximately $139.5 million in cash to the former stockholders of Mission. In addition, all outstanding options to purchase Mission common stock were converted into options to purchase Petrohawk common stock using the exchange ratio of 0.7641 shares of Petrohawk common stock per share of Mission common stock underlying each option. We also assumed Mission s long-term debt of approximately $184 million. At December 31, 2004, Mission s estimated net proved reserves were approximately 226 Bcfe.

Major properties in the asset base included interests in three significant fields in the Permian Basin. The Jalmat field in Lea County, New Mexico, had approximately 56 Bcfe of estimated proved reserves; the Waddell Ranch field in Crane County, Texas had approximately 45 Bcfe of estimated proved reserves; and the TXL Field in Ector County, Texas had approximately 24 Bcfe of estimated proved reserves. Mission also owned significant interests in the Gulf Coast and South Texas regions.

Proton Oil & Gas Corporation

On February 25, 2005, we completed the purchase of Proton Oil & Gas Corporation (Proton) for approximately $53 million. This privately negotiated transaction included internally estimated proved reserves of approximately 28 Bcfe and had an economic effective date of January 1, 2005. The Proton properties are located in South Louisiana and South Texas.

Major properties in the asset base included interests in the Gueydan field in Vermilion Parish, Louisiana, with 16 Bcfe of estimated proved reserves, 1,018 gross acres and nine proved undeveloped (PUD) locations. In South Texas, significant properties included interests in the Heard Ranch field in Bee County, Texas with approximately 7 Bcfe of estimated proved reserves, 4,230 gross acres and 15 PUD locations. The acquisition also included 3-D seismic data covering all major properties.

Sale of Royalty Interest Properties

On February 25, 2005, we completed the disposition of 26 Bcfe of estimated proved reserves of certain royalty interest properties with estimated production of approximately 5 Mmcfe/d for approximately $80 million in cash.

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Business Strategy

We are an independent oil and gas company engaged in the acquisition, development, production and exploration of oil and gas properties located in North America. Our primary objective is to increase shareholder value. To accomplish this objective, our business strategy is focused on the following:

Pursuit of Strategic Acquisitions. We continually review opportunities to acquire producing properties, leasehold acreage and drilling prospects. We seek negotiated transactions to acquire operational control of properties that we believe have significant exploitation and exploration potential. Our strategy includes a significant focus on increasing our holdings in fields and basins in which we already own an interest.

Further Exploitation of Existing Properties. We seek to add proved reserves and increase production through the use of advanced technologies, including detailed reservoir engineering analysis, drilling development wells utilizing sophisticated techniques and selectively recompleting existing wells. We also focus on reducing the per unit operating costs associated with our properties. We believe that many of the properties we have acquired have significant potential and in certain cases have not been actively developed in the past.

Growth Through Exploration. We conduct an active technology-driven exploration program that is designed to complement our property acquisition and development drilling activities with moderate to high risk exploration projects that may have greater reserve potential.

Property Portfolio Management. We continually evaluate our property base to identify opportunities to divest non-core, higher cost or less productive properties with limited development potential. This strategy allows us to focus on a portfolio of core properties with significant potential to increase our proved reserves and production.

Maintenance of Financial Flexibility. We intend to maintain substantial borrowing capacity under our senior revolving credit facility. We believe our internally generated cash flows, our borrowing capacity and access to the capital markets will provide us with the financial flexibility to pursue additional acquisitions of producing properties and leasehold acreage and to execute our drilling program. Another component of our financial management strategy includes the use of hedges to secure product prices for a substantial portion of our expected production.

Benefit from the Transactional Nature of Our Industry. The independent exploration and production industry has been consolidating for a number of years. Our business strategy embraces this trend. We intend to assemble a portfolio of quality proved reserves and drilling opportunities within a core group of operated properties that may potentially be desirable as a strategic acquisition target by larger industry participants.

Oil and Gas Reserves

The December 31, 2005 proved reserve estimates presented in this document were prepared by Netherland, Sewell and Associates, Inc. (Netherland, Sewell). For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell and other information about our oil and gas reserves, see Item 8. Consolidated Financial Statements and Supplementary Data, *Supplemental Oil and Gas Information*. Our reserves are sensitive to commodity prices and their effect on economic producing rates. Our estimated proved reserves are based on oil and gas spot market prices in effect on the last trading day of December 2005.

There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Therefore, the reserve information in this Form 10-K represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and 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 and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced.

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The following table presents certain information as of December 31, 2005 and excludes information relating to the reserves and properties acquired in the North Louisiana Acquisitions. Shut-in wells currently not capable of production are excluded from the producing well information.

	Anadarko Basin	**South Texas**	**Permian Basin**	**East Texas and North Louisiana**	**Arkoma Basin**	**Gulf Coast**	**Other**	**Gulf of Mexico (2)**	**Total**
Proved Reserves at Year End (Bcfe)									
Developed	47.4	41.3	127.9	11.7	13.9	47.8	7.5	14.5	312.0
Undeveloped	8.8	26.9	48.5	6.2	3.7	20.0	0.5	10.7	125.3
Total	56.2	68.2	176.4	17.9	17.6	67.8	8.0	25.2	437.3
Gross Wells	941	317	1,745	607	470	364	209	223	4,876
Net Wells (1)	143.1	80.9	331.7	54.4	79.3	118.8	21.6	26.9	856.7

(1) *The term net as used in net production throughout this document refers to amounts that include only acreage or production that is owned by the Company and produced to its interest, less royalties and production due to others. Net Wells represents our working interest share of each well.*

(2) *The Gulf of Mexico properties are expected to be sold by March 31, 2006.*

Anadarko

The West Edmond Hunton Lime Unit, or WEHLU, is our largest property in this region, covering 30,000 acres (approximately 47 square miles) primarily in Oklahoma County, Oklahoma. The WEHLU field, originally discovered in 1942, is the largest Hunton Lime formation field in the state of Oklahoma. The field has 38 oil and natural gas wells (36 currently producing) with stable production holding the entire unit. We own a 98% working interest and 80% net revenue interest in the majority of the field. Additionally, we have an agreement with a private company to jointly develop additional reserves and production in a portion of WEHLU. The area of mutual interest created by the agreement covers 5,680 acres located in the central northwest portion of the field and we own a 40% working interest and 33% net revenue interest in this area. Two successful horizontal wells were drilled in 2005 and we expect to drill as many as six additional horizontal wells in WEHLU in 2006.

In the Lipscomb field in Lipscomb County, Texas the Tyson A #4H (50% working interest and 37% net revenue interest) has been recently completed as a horizontal well in the Cleveland sand and had initial production in excess of 3 Mmcfe/d. We expect to drill six additional wells in this field during 2006.

South Texas

Our properties in South Texas produce primarily from the Vicksburg, Wilcox and Frio formations, which range in depth from approximately 5,500 to 15,000 feet. We believe that the South Texas region will continue to be a key area for us for potential growth via our drilling program. Also, we are expanding our exploration activities in South Texas through joint ventures with other experienced operators covering up to 800 square miles. This program involves the merging and reprocessing of multiple 3-D seismic data sets and is designed to identify, evaluate and drill deeper objectives within the Wilcox, Vicksburg and Frio trends in this core exploration area. We estimate that we will own and be the operator of approximately 50% of the working interest associated with this program.

In the Lions field, located in Goliad County, we put three new high rate wells on production during the fourth quarter of 2005. These wells, the Petrohawk Weise #2 (50% working interest and 38% net revenue interest), Wright Materials #3 ST2 (28% working interest and 20% net revenue interest) and Weise GU A #1 (32% working interest and 24% net revenue interest), were all completed from multiple Lower Wilcox sands and had combined early production rates of 41 Mmcfe/d gross and 13 Mmcfe/d net. Production is currently constrained due to limitations imposed by treatment facilities in the field. These facilities are in the process of being upgraded and should allow for a significant increase in production from the field. Two to four additional wells are planned during 2006 in the Lions field, with continued development beyond 2006. Additionally, we are in the process of acquiring a high density 3-D seismic survey to better image the complexities of the field.

Gross reserve potential for the field is estimated to be in the range of 50-100 Bcfe. The La Reforma field, located in Starr and Hidalgo Counties, is a significant Vicksburg formation field, and we own between 25% and 50% working interest in this area. We are continuing our successful drilling program in the Lower Vicksburg formation in this field.

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The Guerra D #2 (50% working interest and 38% net revenue interest) was recently completed from multiple Vicksburg sands, which resulted in early production rates in excess of 9 Mmcfe/d. We and our partners intend to maintain an aggressive drilling program in this field through 2006, partially supported by the acquisition of significant additional acreage within our area of mutual interest by virtue of a recently announced farm-in. Additionally, we have merged and reprocessed over 100 square miles of 3-D seismic data within this field area and are actively pursuing the acquisition of additional leases. The Vicksburg formation in this area is complexly faulted and 3-D seismic data is extensively utilized to identify optimal structural targets. Wells in this field typically produce at initial rates of over 10 Mmcfe/d. Other Vicksburg/Frio fields in which we own a meaningful interest include Los Indios, Nabors, Ann Mag and McAllen Ranch.

We are in the process of completing our first well in the Provident City field in Colorado County. The Petrohawk Garrett #1 (55% working interest and 43% net revenue interest) encountered multiple Lower Wilcox sands between 13,300 and 15,700 feet. We have perforated and fracture stimulated three intervals in the well, and it was recently placed on production. Additionally, we are currently merging and reprocessing 3-D seismic data covering 200 square miles with the anticipation of further enhancing the area s exploration potential, as well as actively acquiring leases covering additional prospective areas in this complex Lower Wilcox trend. We intend to drill at least two additional wells in this area in 2006.

In Matagorda County, we recently reached total depth on the Petrohawk Doss #1 (50% working interest and 40% net revenue interest) and anticipate first production from this well during the first quarter of 2006. This well is located within a large amplitude anomaly in the Lower Frio formation, which we believe has potential for a significant discovery. We are in the process of merging and reprocessing 3-D seismic data covering in excess of 300 square miles, as well as actively acquiring leases covering other prospective areas within this trend. Two additional wells are budgeted for 2006.

The Heard Ranch field, located in Bee County, was acquired in the Proton transaction and produces from the Frio formation at depths from 3,000 to 4,500 feet. We own between a 77% and an 89% working interest with between 56% and 65% net revenue interest at Heard Ranch and plan to drill up to four proved undeveloped and two probable locations in 2006. In the San Miguel Creek field in McMullen County, we anticipate drilling six Wilcox formation wells in 2006.

Permian Basin

In the Permian Basin, our principal properties are in the Waddell Ranch field in Crane County, Texas, the TXL field located in Ector County, Texas and the Jalmat field in Lea County, New Mexico. Since the acquisition of our Permian Basin assets, we have extensively examined and evaluated these properties. Our objective is to determine if unevaluated proved reserves and additional upside opportunities exist within these long-lived, multi-pay fields.

Waddell Ranch is our largest field in West Texas and produces primarily from the Queen, Grayburg, San Andres, Clear Fork, and Ellenburger formations at depths from 3,000 to 15,000 feet. The Waddell Ranch field complex is comprised of over 75,000 acres and is productive from over 15 different reservoirs. The development opportunities in this field continue to evolve through technical evaluation. Our staff has implemented a rigorous engineering and geological study over the past nine months. The results of this field study are the identification of over 1,000 additional potential drilling locations. This project has resulted in the addition of proved reserves at year end 2005, with the potential of continued reserve additions in future years. After review of this study with our working interest partners, we concluded that the 2006 capital budget would be increased to include the drilling of 30 new wells and 90 recompletions.

The TXL field located in Ector County, Texas is a unitized field in the Clearfork Tubb formation at approximately 5,600 feet. As a result of our ongoing evaluation, over 100 additional drill sites have been evaluated which we believe will lead to additional proved reserves as well as upside potential. As many as 20 wells are planned to be drilled in 2006 in this field.

The Jalmat field in Lea County, New Mexico is slated for an aggressive development drilling program in the Seven Rivers formation which contains over 55 proved developed locations and over 90 probable locations. We plan activity for at least 26 locations during 2006 (10 new wells and 16 recompletions) and may accelerate this program if additional drilling rigs can be secured. Our extensive evaluation of this area has resulted in the identification of significant waterflood potential in the Queen sand, a reservoir that has had excellent waterflood results from numerous offsetting units. We own a 96% working interest and 83% net revenue interest in this field.

North Louisiana and East Texas

The properties acquired in the North Louisiana Acquisitions in January 2006 are located in the Elm Grove and Caspiana fields in North Louisiana. Current production is approximately 16 Mmcfe/d from the Cotton Valley and Hosston formations. We have identified 250 drilling locations on the 27,400 acre block and plan on a multi-year development program. In 2006, we have budgeted $35 million for development drilling on these properties.

Our properties in the East Texas basin produce primarily from the Cotton Valley and Travis Peak/Hosston formations, which range in depth from approximately 6,500 to 10,000 feet. We own significant interests in the South Carthage, North Beckville and Blocker fields in Panola and Harrison Counties, Texas. Our working interest in these fields is between 47% and 100%. The producing formations of this area tend to contain multiple producing horizons and are typically low permeability sands that require fracture stimulation to achieve optimal producing rates. This type of fracture stimulation usually results in relatively high initial production rates that decline rapidly during the first year of production and subsequently stabilize at fairly low, more easily predictable annual decline rates. Much of our production in this area is from wells that have been producing for several years and are in the latter, more stable stage of production, resulting in a relatively long reserves-to-production ratio.

We have been actively acquiring acreage in the developing James Lime horizontal play and in the Travis Peak vertical play in Nacogdoches, Shelby and Angelina Counties, Texas. We have acquired over 14,000 net acres to date, and we anticipate adding significant acreage to our position through additional leasing and farm-out negotiations. The initial well was spud during February 2006 and is currently being completed. We plan on maintaining a one-rig program in this area throughout 2006 with the intent to add a second rig pending drilling success and rig availability.

Arkoma

In the Arkoma region, our properties produce primarily from the Atoka formation at depths of 2,500 to 6,000 feet. We own significant interests in the Hichita, Pine Hollow, Kinta and Cedars fields in Pittsburg, Haskell and McIntosh Counties, Oklahoma. Our working interest in these fields is between 23% and 100%.

We believe that the Pine Hollow field in Pittsburg County, Oklahoma has multiple drilling opportunities. We intend on participating with a 25% working interest in up to 25 horizontal wells in the Hartshorne Coal Bed Methane play in 2006. Additionally, we anticipate the operator will continue its development of the horizontal Woodford Shale play in which we have working interest ranging from 5% to 20%.

In the Hichita field in McIntosh County, Oklahoma we own an approximate 75% working interest in over 15,000 gross acres that are within the Caney Shale play. We intend on testing the Caney Shale with a horizontal well during 2006. In addition to the Caney Shale, we believe the Hartshorne Coal is prospective for horizontal development in this area and we are currently evaluating its potential.

We plan to spud the initial two exploratory wells on the 120,000 gross acre block we control in the eastern area of the Arkoma Basin during the second quarter of 2006. Both wells on our Flower Prospect (76% working interest, 60% net revenue interest) are planned to examine numerous potential objectives. The first well s primary objective is the Jackfork formation at approximately 12,700 feet. The second well is expected to target typical Arkoma Basin Atokan objectives at depths between 7,000 and 10,000 feet.

Gulf Coast

The Gueydan field in Vermilion Parish, Louisiana is our most significant field in the Gulf Coast region and was acquired as part of the acquisition of Proton. Production in this field is from 2,500 to 10,000 feet in depth. Our working interest ranges from 50% to 100%, and we plan to drill 10 wells in 2006 in the Gueydan field. We enjoyed significant success during 2005 with our drilling program in this field. In addition to the development of the 2,700 foot sands with the Alliance #45, #50 and #51 (100% working interest, 78% net revenue interest), drilling has continued in deeper Alliance Sand wells at approximately 9,500 feet. Most recently, the Noble #1 (50% working interest and 39% net revenue interest) has been completed and is producing at a gross rate of 3 Mmcfe/d. In addition, the Alliance #47 (98% working interest and 81% net revenue interest) was logged and confirmed 45 feet of high quality pay sand. We have also leased approximately 2,000 additional acres within the area, and are in the process of conducting a new 3-D seismic survey to confirm additional prospects. In 2006, six shallow exploratory wells, three 9,500 foot Alliance Sand developmental wells, and one 16,000 foot deep Frio exploratory well are budgeted. Other significant fields in this region include South Bayou Boeuf in LaFourche Parish, Louisiana, Reddell in Evangeline Parish, Louisiana and

North Leroy in Vermilion Parish, Louisiana.

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Gulf of Mexico

At December 31, 2005 we owned interests in 28 blocks in the federal waters of the Gulf of Mexico. Our largest fields in this region are High Island A-553, Ship Shoal 208/239, South Marsh Island 142, High Island A-334 and Ship Shoal 246. The majority of our interests in the Gulf of Mexico are non-operated. Net production from our Gulf of Mexico properties was approximately 15 Mmcfe/d in September 2005 when Hurricane Rita required all of these properties to be shut-in. Since October 2005, the majority of our Gulf of Mexico properties have returned to production with the remainder expected to be back on line by the end of March 2006, subject to third party pipelines and onshore processing plants being returned to full operating status. We believe we did not sustain any significant damage to any of our offshore properties during either Hurricane Katrina or Hurricane Rita.

In West Cameron Block 39, drilling operations resumed in early January, after hurricane-related delays, on the 21,000-foot MD Lower Miocene test operated by Norsk-Hydro. We own a 10% working interest (8.5% net revenue interest) in the well and anticipate reaching total depth prior to the end of the second quarter of 2006. This interest is not included in the package of properties in the Gulf of Mexico.

On February 3, 2006, we entered into a definitive agreement with Northstar GOM, LLC to sell substantially all of our Gulf of Mexico properties for $52.5 million in cash. These properties have estimated proved reserves as of December 31, 2005 of approximately 25 Bcfe, are approximately 70% gas, 59% proved developed and 27% operated. Current production is estimated to be approximately 10 Mmcfe/d. The transaction is expected to close by March 31, 2006.

Risk Management

We use hedges to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While there are many different types of derivatives available, we primarily use oil and gas price collar and swap agreements to attempt to manage price risk more effectively. The collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of oil and gas for the period is greater or less than the fixed price established for that period when the swap is put in place. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor. We only enter into derivatives arrangements with credit worthy counterparties. These arrangements expose us to the risk of financial loss if our counterparty is unable to satisfy its obligations. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A Quantitative and Qualitative Disclosures about Market Risk for additional information.

Oil and Gas Operations

Our principal properties consist of developed and undeveloped oil and gas leases and the reserves associated with these leases. Generally, developed oil and gas leases remain in force so long as production is maintained. Undeveloped oil and gas leaseholds are generally for a primary term of three to five years. In most cases, the term of our undeveloped leases can be extended by paying delay rentals or by producing reserves that are discovered under those leases.

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The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive [(1)]	8	2.40	2	0.57	2	0.39
Dry	5	1.29	5	0.42	1	0.35
Total Exploratory	13	3.69	7	0.99	3	0.74
Development Wells:						
Productive [(1)]	129	27.40	61	10.79	18	4.34
Dry	4	1.35	3	0.15	7	1.94
Total Development	133	28.75	64	10.94	25	6.28
Total Wells:						
Productive [(1)]	137	29.80	63	11.36	20	4.73
Dry	9	2.64	8	0.57	8	2.29
Total	146	32.44	71	11.93	28	7.02

(1) *Although a well may be classified as productive upon completion, future production may deem the well to be uneconomical, particularly exploratory wells where there is no production history.*

We own interest in developed and undeveloped oil and gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and gas leases or licenses that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2005:

State	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Alabama	1,920	174			1,920	174
Arkansas	16,978	3,712	110,610	68,591	127,588	72,303

Kansas	16,540	5,512	8,865	3,519	25,405	9,031
Louisiana	63,797	9,720	5,601	2,431	69,398	12,151
Mississippi	7,120	745			7,120	745
New Mexico	30,440	11,866			30,440	11,866
North Dakota	9,680	795			9,680	795
Oklahoma	256,386	77,035	1,156	569	257,542	77,604
Oregon	2,400	1,187			2,400	1,187
South Dakota	1,920	320			1,920	320
Texas	419,056	104,390	23,651	13,694	442,707	118,084
Utah	14,720	1,506			14,720	1,506
Wyoming	15,561	1,206			15,561	1,206
Offshore	218,720	36,594	845	185	219,565	36,779
Total Acreage	1,075,238	254,762	150,728	88,989	1,225,966	343,751

At December 31, 2005, we had estimated proved reserves of approximately 262 Bcf of natural gas and 29.2 MMBbls of oil located onshore in the United States and offshore in the Gulf of Mexico. The following table sets forth, at December 31, 2005, these reserves:

	Proved Developed	**Proved Undeveloped**	**Total Proved**
Gas (Bcf)	177.6	84.3	261.9
Oil (MMBbls)	22.4	6.8	29.2

The estimates of quantities of proved reserves above were made in accordance with the definitions contained in SEC Regulation S-X, Rule 4-10(a).

For additional information on our oil and gas reserves, see Item 8. Consolidated Financial Statements and Supplementary Data, *Supplementary Oil and Gas Information*.

We account for our oil and gas producing activities using the full cost method of accounting as prescribed by the SEC. Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general corporate costs are expensed as incurred. Sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and gas properties are subject to a full cost ceiling test.

Capitalized costs of our evaluated and unevaluated properties at December 31, 2005, 2004 and 2003 are summarized as follows:

	December 31,		
	2005	2004	2003
	(in thousands)		
Capitalized costs:			
Evaluated properties	$ 1,096,810	$ 484,233	$ 78,717
Unevaluated properties	162,133	48,840	1,294
	1,258,943	533,073	80,011
Less accumulated depreciation and depletion	(121,456)	(48,740)	(39,740)
	$ 1,137,487	$ 484,333	$ 40,271

Our oil and gas production volumes and average sales price are as follows:

	Years Ended December 31,		
	2005	2004	2003
Gas production (MMcf)	20,219	3,569	1,859
Oil production (MBbl)	1,555	244	129
Equivalent production (MMcfe)	29,549	5,030	2,632
Average price per unit:			
Gas (per Mcf)	$ 8.46	$ 6.53	$ 4.71
Oil (per Bbl)	55.62	40.71	27.36
Equivalent (per Mcfe)	8.73	6.61	4.78

The 2005 and 2004 average oil and gas sales prices above do not reflect the impact of cash paid on settled contracts as these amounts are reflected as other income and expenses in the consolidated statement of operations, consistent with our decision not to elect hedge accounting. Including the realized impact of derivatives, 2005 and 2004 gas prices were $7.32 and $6.41 per Mcf and our realized oil prices were $47.20 and $37.76 per Bbl, respectively. In 2003, we designated our derivatives as cash flow hedges and applied hedge accounting. Consistent with this decision, the average oil and gas prices for 2003 above already reflect the impact of cash paid on settled contracts. The 2003 average natural gas price above was reduced by $0.59 per Mcf and the average crude oil price above was reduced by $1.80 per Bbl.

Competitive Conditions in the Business

The oil and gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and gas, as well as, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, locating and obtaining sufficient rig and platform availability, and obtaining purchasers and transporters of the oil and gas we produce. There is also competition between oil and gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States; however, it is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing oil and gas and may prevent or delay the commencement or continuation of a given operation. The exact effect of these risk factors cannot be accurately predicted.

Other Business Matters

Markets and Major Customers

In 2005, we had one individual purchaser that accounted for approximately 12% of our total sales. In 2004, we had no individual customers accounting for more than 10% of our total sales. In 2003, approximately 53% of our total sales were made to three individual customers. We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and gas we produce. We believe other purchasers are available in our areas of operations.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of results, which may be realized on an annual basis.

Operational Risks

Oil and gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and gas in commercial quantities. Oil and gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other circumstances that may cause accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property may occur. In such event, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could substantially reduce available cash and possibly result in loss of oil and gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities. We are not aware of any of these instances that have occurred to date that need to be accrued for.

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations. For further discussion on risks see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations.

Regulations

Domestic exploration for, and production and sale of, oil and gas are extensively regulated at both the federal and state levels. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and gas industry that often are costly to comply with and that carry substantial penalties for failure to comply. In addition, production operations are affected by changing tax and other laws relating to the petroleum industry, constantly changing administrative regulations and possible interruptions or termination by government authorities.

State regulatory authorities have established rules and regulations requiring permits for drilling operations, drilling bonds and reports concerning operations. Most states in which we operate also have statutes and regulations governing a number of environmental and conservation matters, including the unitization or pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Many states also restrict production to the market demand for oil and gas. Such statutes and regulations may limit the rate at which oil and gas could otherwise be produced from our properties.

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We are subject to extensive and evolving environmental laws and regulations. These regulations are administered by the United States Environmental Protection Agency and various other federal, state, and local environmental, zoning, health and safety agencies, many of which periodically examine our operations to monitor compliance with such laws and regulations. These regulations govern the release of waste materials into the environment, or otherwise relating to the protection of the environment, human, animal and plant health, and affect our operations and costs. In recent years, environmental regulations have taken a cradle to grave approach to waste management, regulating and creating liabilities for the waste at its inception to final disposition. Our oil and gas exploration, development and production operations are subject to numerous environmental programs, some of which include solid and hazardous waste management, water protection, air emission controls and situs controls affecting wetlands, coastal operations and antiquities.

Environmental programs typically regulate the permitting, construction and operations of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Once operational, enforcement measures can include significant civil penalties for regulatory violations regardless of intent. Under appropriate circumstances, an administrative agency can request a cease and desist order to terminate operations.

New programs and changes in existing programs are anticipated, some of which include natural occurring radioactive materials, oil and gas exploration and production waste management and underground injection of waste materials. Each state in which we operate has laws and regulations governing solid waste disposal, water and air pollution. Many states also have regulations governing oil and gas exploration, development and production operations.

We are also subject to federal and state Hazard Communications and Community Right to Know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances. We believe we are in compliance with these requirements in all material respects.

We may be required in the future to make substantial outlays to comply with environmental laws and regulations. The additional changes in operating procedures and expenditures required to comply with future laws dealing with the protection of the environment cannot be predicted.

Employees

As of December 31, 2005, we had 154 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Exchange Act of 1934, as amended, or the Exchange Act. We make our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to such reports available free of charge through our corporate website at www.petrohawk.com as soon as reasonably practicable after we file any such report with the SEC. You may also read and copy any document we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site that contains our reports, proxy and information statements, and our other filings which are also available to the public over the Internet at the SEC s website at www.sec.gov. In addition, information related to the following items, among other information, can be found on our website: (1) our press releases, (2) our corporate governance guidelines, (3) our code of conduct, (4) our audit committee charter, (5) our compensation committee charter, and (6) our nominating committee charter.

ITEM 1A. RISK FACTORS

Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on prevailing oil and gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we will be able to borrow under our senior revolving credit facility will be subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may also reduce the amount of oil and gas that we can economically produce and have an adverse effect on the value of our properties. Prices for oil and gas have increased significantly and been more volatile over the past twelve months. Historically, the markets for oil and gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

- the domestic and foreign supply of oil and gas;
- the ability of members of the Organization of Petroleum Exporting Countries, or OPEC, and other producing countries to agree upon and maintain oil prices and production levels;
- political instability, armed conflict or terrorist attacks, whether or not in oil or gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and gas producing regions;
- weather conditions, including hurricanes;
- the price and availability of alternative fuels;
- the price of foreign imports;
- worldwide economic conditions; and
- the availability of liquid natural gas imports.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and gas.

In addition, the borrowing base limitation under our senior revolving credit facility is determined on a semi-annual basis at the discretion of our banks and is based, in part, on oil and gas prices. If the banks set our borrowing base at an amount below the aggregate principal amount of our debt outstanding under that facility, we could be required to repay a portion of our bank debt. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the loan agreement and an acceleration of the loan.

Assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our recent growth is due significantly to acquisitions of exploration and production companies, producing properties and undeveloped leaseholds. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and gas prices, operating and capital costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties.

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As a result of these factors, we may not be able to acquire oil and gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Estimates of oil and gas reserves are uncertain and any material inaccuracies in these reserve estimates will materially affect the quantities and the value of our reserves.

This report on Form 10-K contains estimates of our proved oil and gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and gas reserves and the costs associated with development of these reserves in accordance with SEC regulations, we cannot assure you that the estimated costs or estimated reserves are accurate, that development will occur as scheduled or that the actual results will be as estimated.

We intend to fund our development, acquisition and exploration activities in part through additional debt financing. A higher level of debt could negatively impact our financial condition, results of operations and business prospects.

As of December 31, 2005, we had approximately $500 million of long term debt, including $2.8 million of long term debt that is required to be repaid in the next 12 months. As of December 31, 2005, the borrowing base under our senior revolving credit facility was $260 million; however, as of January 31, 2006, it had increased to $400 million, due to the North Louisiana Acquisitions in early 2006. If we incur additional debt in order to fund our development, acquisition and exploration activities or for other purposes, our level of debt, and the covenants contained in the agreements governing our debt, could have important consequences, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;
- the covenants contained in the agreements governing our debt limit, our ability to borrow additional funds, pay dividends, dispose of assets or issue shares of preferred stock and otherwise may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- a leveraged financial position would make us more vulnerable to economic downturns and could limit our ability to withstand competitive pressures; and
- any debt that we incur under our revolving credit facility will be at variable rates which make us vulnerable to increases in interest rates.

In addition, in connection with the Mission merger, we assumed Mission s 9 7/8% senior notes in the aggregate principal amount of $130 million. The notes contain covenants that, subject to certain exceptions and qualifications, limit our ability and the ability of our subsidiaries to incur and guarantee additional indebtedness, issue certain types of equity securities, transfer or sell assets, or pay dividends. Additionally, transactions with affiliates, selling stock of a subsidiary, merging or consolidating are subject to qualifications.

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Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage in order to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that all of our prospects will result in viable projects or that we will not abandon our initial investments. Additionally, we cannot guarantee that the leasehold acreage we acquire will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results are dependent upon the current and future market prices for oil and gas, costs associated with producing oil and gas and our ability to add reserves at an acceptable cost. We rely to a significant extent on 3-D seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The 3-D seismic data and other technologies we use do not allow us to know conclusively prior to acquisition of leasehold acreage or drilling a well whether oil or gas is present or may be produced economically. The use of 3-D seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

In addition, we may not be successful in implementing our business strategy of controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, including hurricanes;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

Our ability to finance our business activities will require us to generate substantial cash flow.

Our business activities require substantial capital. We intend to finance our capital expenditures in the future through cash flow from operations, the incurrence of additional indebtedness and/or the issuance of additional equity securities. We cannot be sure that our business will continue to generate cash flow at or above current levels. Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the level of production from existing wells;
- prices of oil and gas;
- our results in locating and producing new reserves;
- the success and timing of development of proved undeveloped reserves; and
- general economic, financial, competitive, legislative, regulatory and other factors beyond our control.

If we are unable to generate sufficient cash flow from operations to service our debt, we may have to obtain additional financing through the issuance of debt and/or equity. We cannot be sure that any additional financing will be available to us on acceptable terms. Issuing equity securities to satisfy our financing requirements could cause substantial dilution to our existing stockholders. The level of our debt financing could also materially affect our operations.

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If our revenues were to decrease due to lower oil and gas prices, decreased production or other reasons, and if we could not obtain capital through our senior revolving credit facility or otherwise, our ability to execute our development and acquisition plans, replace our reserves or maintain production levels could be greatly limited.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our future performance will be substantially dependent on retaining key members of our management. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows. We currently do not have employment agreements with any of our officers.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. As a result of increasing levels of exploration and production in response to strong prices of oil and natural gas, the demand for oilfield services has risen, and the costs of these services are increasing, while the quality of these services may suffer. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in Texas and Louisiana, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

The marketability of our oil and gas production depends on services and facilities that we typically do not own or control. The failure or inaccessibility of any such services or facilities could result in a curtailment of production and revenues.

The marketability of our production depends in part upon the availability, proximity and capacity of gathering systems, pipelines and processing facilities. Pursuant to interruptible or short term transportation agreements, we generally deliver gas through gathering systems and pipelines that we do not own. Under the interruptible transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. If any of the pipelines or other facilities become unavailable, we would be required to find a suitable alternative to transport and process the gas, which could increase our costs and reduce the revenues we might obtain from the sale of the gas. For example, Hurricane Rita disrupted the operations of gas pipelines and processing plants and required the evacuation of personnel required to oversee some of our facilities in the Gulf Coast and Gulf of Mexico areas.

We depend on the skill, ability and decisions of third party operators to a significant extent.

The success of the drilling, development and production of the oil and gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could negatively affect our results of operations.

Our business is highly competitive.

The oil and gas industry is highly competitive in many respects, including identification of attractive oil and gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

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Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our oil and gas production, from time to time we enter into oil and gas price hedging arrangements with respect to a portion of our expected production. While intended to reduce the effects of volatile oil and gas prices, such transactions may limit our potential gains and increase our potential losses if oil and gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or
- the counterparties to our hedging agreements fail to perform under the contracts.

Our oil and gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

- human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- environmental regulations and requirements;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment;
- changes in laws and regulations, including laws and regulations applicable to oil and gas activities or markets for the oil and gas produced;
- fluctuations in supply and demand for oil and gas causing variations of the prices we receive for our oil and gas production; and
- the internal and political decisions of OPEC and oil and natural gas producing nations and their impact upon oil and gas prices.

As a result of these risks, expenditures, quantities and rates of production, revenues and cash operating costs may be materially adversely affected and may differ materially from those anticipated by us.

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Governmental and environmental regulations could adversely affect our business.

Our business is subject to federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and gas and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

Our operations are also subject to complex environmental laws and regulations adopted by the various jurisdictions in which we have or expect to have oil and gas operations. We could incur liability to governments or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water, including responsibility for remedial costs.

We could potentially discharge these materials into the environment in any of the following ways:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and gas wells resulting from accidents during normal operations; and
- blowouts, hurricanes, cratering and explosions.

Because the requirements imposed by laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, because we acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage caused by the former operators.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

There can be no assurance that this insurance coverage will be sufficient to cover every claim made against us in the future. A loss in connection with our oil and natural gas properties could have a materially adverse effect on our financial position and results of operation to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.

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Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or failure. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1. Business and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

From time to time we may be a defendant and plaintiff in various legal proceedings arising in the normal course of our business. All known liabilities are accrued based on management s best estimate of the potential loss. While the outcome and impact of such legal proceedings cannot be predicted with certainty, our management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our consolidated financial position, results of operations or cash flow.

Andrew A. Roth, as a nominal plaintiff, filed a lawsuit against us, certain of our directors and certain of our current and former stockholders, including PHAWK, LLC, alleging violations of Section 16(b) of the Exchange Act of 1934, as amended. The lawsuit seeks recovery, on our behalf, of alleged short-swing profits of at least $6,465,000. Mr. Roth filed the lawsuit in the United States District Court for the Southern District of New York on October 31, 2005 as *Andrew A. Roth derivatively on behalf of Petrohawk Energy Corporation v. PHAWK, LLC, et. al.,* and the case was assigned Civil Case Number: 05 CV 9247. Pursuant to an August 1, 2005 demand letter from Mr. Roth, an independent committee of the board of directors investigated Mr. Roth s claims prior to the filing of the lawsuit and concluded they had no merit. We are monitoring developments in the matter with legal counsel. We do not believe this litigation shall have a material effect on our financial position or results of operations, should the plaintiff s allegations be found to be accurate.

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

No matters were submitted to a vote of our shareholders during the fourth quarter of the fiscal year ended December 31, 2005.

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PART II

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

Our common stock began trading July 16, 2004 on the Nasdaq National Market under the symbol HAWK. Prior to July 16, 2004, our common stock traded on the Nasdaq National Market under the symbol BETA. The following table sets forth the high and low intra-day sales prices per share of our common stock as reported on the Nasdaq National Market. The high and low amounts for periods prior to May 26, 2004 have been adjusted to reflect the one-for-two reverse split of our common stock effective on that date.

	High	Low
2005		
First Quarter	$10.98	$ 7.45
Second Quarter	11.94	7.57
Third Quarter	14.91	10.45
Fourth Quarter	15.17	11.02
2004		
First Quarter	$ 7.84	$ 3.70
Second Quarter	9.57	5.50
Third Quarter	8.80	6.40
Fourth Quarter	9.89	7.85

We have never paid cash dividends on our common stock. We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Holders of our 8% cumulative convertible preferred stock are entitled to receive cumulative dividends at the annual rate of $0.74 per share. No dividends may be paid on common stock unless all cumulative dividends due on 8% cumulative convertible preferred stock have been declared and paid. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including our prospects, and such other factors, as the board of directors deems relevant. We are also restricted from paying cash dividends on common stock under our revolving credit facility.

Approximately 268 shareholders of record as of December 31, 2005 held our common stock. In many instances, a registered shareholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

A description of our equity compensation plan information is incorporated by reference from our definitive proxy statement to be filed with respect to our 2006 annual meeting under the heading Executive Compensation.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

We did not purchase any of our equity securities during the fourth quarter of 2005. In addition, we did not sell any of our equity securities which were not registered under the Securities Act of 1933, as amended, during the fourth quarter of 2005. At December 31, 2005, we held 8,382 shares of common stock as treasury shares.

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ITEM 6. SELECTED HISTORICAL FINANCIAL DATA

The following table presents selected historical financial data derived from our consolidated financial statements. The following data is only a summary and should be read with our historical consolidated financial statements and related notes contained in this document. The acquisition of Mission in 2005 and of Wynn-Crosby in 2004 affects the comparability between the consolidated financial data for the periods presented.

	Year ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
	(in thousands, except per share data)				
Income Statement Data:					
Oil and gas sales	$ 258,039	$ 33,577	$12,925	$ 9,648	$ 13,657
Income from operations	103,890	4,699	1,496	(6,347)	(11,813)
Net (loss) income	(16,634)	8,117	968	(6,882)	(9,046)
Net (loss) income applicable to common shareholders	(17,074)	7,672	521	(7,329)	(9,278)
Earnings (loss) per share:					
Basic [1]	$ (0.31)	$ 0.71	$ 0.08	$ (1.18)	$ (1.50)
Diluted [1]	(0.31)	0.36	0.08	(1.18)	(1.50)
Balance sheet data:					
Working (deficit) capital	$ (37,905)	$ 8,856	$ 2,189	$ (77)	$ (104)
Total assets	1,410,174	534,199	46,115	44,753	52,629
Total long-term debt	495,801	239,500	13,285	13,635	13,649
Stockholders equity	526,458	247,091	29,270	28,048	35,874

(1) *On May 18, 2004, our Board of Directors approved a one-for-two reverse stock split that was effective May 26, 2004. The reverse stock split was implemented to effect the conditional approval by the NASDAQ National Market of our listing application, which was later formally approved. As a*

result, all prior year common stock share amounts have been restated to reflect this reverse stock split in the chart above.

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

The following discussion is intended to assist in understanding our results of operations and our present financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Form 10-K contain additional information that should be referred to when reviewing this material.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Overview

We are a independent oil and gas company engaged in the acquisition, development, production and exploration of oil and gas properties located in North America. Our properties are concentrated in the Permian Basin, East Texas, North Louisiana, Gulf Coast, South Texas, Anadarko and Arkoma regions. We have increased our proved reserves and production principally through acquisitions in conjunction with an active drilling program. Since November 2004, we have acquired approximately 535 Bcfe of proved reserves for approximately $1.2 billion, including the recently completed North Louisiana Acquisitions. During 2005, excluding acquisitions, we replaced approximately 149% of our production organically. Organic reserve additions were primarily driven by 3D seismic supported exploratory drilling in our core regions of South Texas and the Gulf Coast, as well as continuing evaluation of several fields in the Permian Basin. Fields that contributed significantly to the growth were the Lions (Goliad County, Texas); Waddell Ranch (Crane County, Texas); Provident City (Colorado County, Texas); La Reforma (Starr County, Texas); and Gueydan (Vermilion Parish, Louisiana). During 2005, we participated in the drilling of 146 wells, of which nine were dry holes, for a success rate of 94%.

We focus on maintaining a balanced, geographically diverse portfolio of long-lived, lower risk reserves along with shorter lived, higher margin reserves. We believe that this balanced reserve mix provides a diversified cash flow foundation to fund our development and exploration drilling program.

Our financial results depend upon many factors, particularly the price of oil and gas and our ability to market our production. Commodity prices are affected by changes in market demands, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future oil and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success.

Capital Resources and Liquidity

Our primary sources of cash in 2005 were from operating and financing activities. Proceeds from the issuance of long term debt and cash received from operations as well as divestitures in 2005 were offset by cash used in investing activities to complete the acquisitions of Mission and Proton. Operating cash flow fluctuations were substantially driven by commodity prices and changes in our production volumes. Prices for oil and gas have historically been subject to seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout the recent years. Working capital was substantially influenced by these variables. Fluctuation in cash flow may result in an increase or decrease in our capital and exploration expenditures. See Results of Operations for a review of the impact of prices and volumes on sales. Cash flows provided by operating activities were primarily used to fund exploration and development expenditures. See below for additional discussion and analysis of cash flow.

	Year Ended December 31, 2005	2004	2003
		(in thousands)	
Cash flows provided by operating activities	$ 135,446	$ 17,943	$ 5,793
Cash flows used in investing activities	(206,109)	(400,481)	(3,546)
Cash flows provided by (used in) financing activities	77,914	386,088	(1,064)
Net increase in cash and cash equivalents	$ 7,251	$ 3,550	$ 1,183

Operating Activities. Net cash provided by operating activities in 2005 increased $117.5 million from 2004. This increase was primarily due to higher commodity prices and an increase in sales volumes in conjunction with the 2005 acquisitions discussed above. Average realized prices increased $2.12 from $6.61 per Mcfe in 2004 to $8.73 per Mcfe in 2005. Production volumes increased 24,519 Mmcfe from 5,030 Mmcfe in 2004 to 29,549 Mmcfe in 2005. We expect 2006 production to increase, but we are unable to predict future commodity prices. As a result, we cannot provide any assurance about future levels of net cash provided by operating activities. Net cash provided by operating activities in 2004 increased $12.2 million from 2003. This increase was primarily due to a 38% increase in the average equivalent price per Mcfe.

Investing Activities. The primary driver of cash used in investing activities was capital spending, inclusive of acquisitions. We establish the budget for these amounts based on our estimate of future commodity prices. Due to the volatility of commodity prices, our budget may be periodically adjusted during any given year. Cash used in investing activities in 2005 decreased $194.4 million from $400.5 million in 2004 to $206.1 million in 2005 primarily due to the nature of financing of our Wynn-Crosby acquisition as compared to our Mission acquisition. In 2004, we spent $384.5 million to acquire Wynn-Crosby for a purchase price of approximately $425 million after closing adjustments. The transaction was funded with proceeds from a $200 million private equity placement, $210 million in borrowings from our commercial bank group and cash.

In 2005, we acquired Mission for consideration consisting of 60.1% of Company common stock and 39.9% cash. In this transaction we paid approximately $96.5 million, net of cash acquired. We also assumed $184 million of Mission s long-term debt. Also in 2005, we acquired Proton for approximately $52.6 million, net of cash acquired. The 2005 acquisitions were offset by the receipt of $88.9 million in 2005, primarily for the sale of certain royalty properties for $80 million. The overall net decrease in cash used in investing activities was offset by an increase in overall capital spending of approximately $109.6 million. In 2005, we drilled 146 gross wells compared to 71 in 2004. Cash flows used in investing activities increased $396.9 million from 2003 to $400.5 million in 2004 primarily due to the acquisition activity discussed above.

On January 27, 2006, the Company completed the acquisition of all of the issued and outstanding common stock of Winwell Resources, Inc. Winwell pursuant to a Stock Purchase Agreement with Winwell and all of its shareholders made and entered into as of December 14, 2005 (the Stock Purchase Transaction). The aggregate consideration paid in the Stock Purchase Transaction was approximately $208 million in cash after certain closing adjustments. Also on January 27, 2006, the Company completed its acquisition of assets pursuant to an Asset Purchase Agreement with Redley, made and entered into as of December 14, 2005, as amended, (the Asset Purchase Transaction). The aggregate consideration paid in the Asset Purchase Transaction was approximately $86 million in cash after certain closing adjustments. The Company deposited $15 million in earnest money under the terms of the Stock Purchase Transaction, and $7.5 million under the terms of the Asset Purchase Transaction. The $22.5 million deposit was included in other non-current assets at December 31, 2005. The deposit and any interest earned thereon was applied to the overall purchase price.

We have established a capital budget of $210 million for 2006 to be funded primarily from cash flows from operations. We establish the budget for these amounts based on our current estimate of future commodity prices. Due to the volatility of commodity prices our budget may be periodically adjusted.

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Financing Activities. Net cash provided by financing activities in 2005 was $77.9 million compared to $386.1 million in 2004. At December 31, 2005, we had $210 million of debt outstanding under our senior revolving credit facility, which provides for a borrowing base of $260 million. It is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks petroleum engineer). We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Management believes that we have the ability to finance through new debt or equity offerings, if necessary, our capital requirements, including potential acquisitions. We also had net borrowings from our long-term debt facilities of $95.5 million due to our acquisition and divestiture activities during the year.

Financing activities in 2005 also included $28.9 million of cash paid on settled derivative contracts that were acquired in conjunction with our acquisition activity.

During 2005, we paid $0.3 million of the $0.4 million declared dividends on our 8% cumulative convertible preferred stock, with the remaining $0.1 million accrued in current liabilities and paid in January 2006.

We believe that we have the ability to finance through new debt or equity offerings, if necessary, our capital requirements, including acquisitions.

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Contractual Obligations

We have no material long-term commitments associated with our capital expenditure plans or operating agreements. Consequently, we believe we have a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, developmental and exploration activities, oil and gas price conditions and other related economic factors. Currently no sources of liquidity or financing are provided by off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities.

The following table summarizes our contractual obligations and commitments by payment periods (in thousands).

		Payments Due by Period			
Contractual Obligations	**Total**	**Less than one year**	**1-3 years**	**3-5 years**	**More than 5 years**
Revolving credit facility	$ 210,000	$	$	$ 210,000	$
Second lien term loan facility [1]	150,000	1,500	3,000	145,500	
9 7/8% senior notes due 2011 [2]	124,484				124,484
Interest expense on long-term debt [3]	170,735	38,469	76,541	52,424	3,301
Deferred premiums on derivatives [4]	4,105	1,288	2,817		
Operating leases	5,840	2,196	2,890	754	
Total contractual obligations	$ 665,164	$ 43,453	$ 85,248	$ 408,678	$ 127,785

(1) *Includes $1.5 million of borrowings that have been classified as current at December 31, 2005.*

(2) *Excludes $10.0 million of unamortized premium associated with the fair value calculation performed in accordance with purchase accounting, related to the Mission merger.*

(3)

Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2005 less required annual repayments.

(4) *Includes $1.3 million of deferred premiums on derivatives that have been classified as current at December 31, 2005.*

Amounts related to our asset retirement obligations are not included in the table above given the uncertainty regarding the actual timing of such expenditures. The total amount of asset retirement obligations at December 31, 2005 is $51.2 million.

Senior Revolving Credit Facility

We entered into a new senior revolving credit facility with BNP Paribas as the lead bank and administrative agent on November 23, 2004, in connection with the acquisition of Wynn Crosby. The $400 million revolving credit facility had an initial borrowing base of $200 million and a threshold amount of $180 million. On April 1, 2005, the borrowing base under the facility was changed to $185 million with a threshold amount of $175 million.

In connection with the Mission merger, we amended and restated our $400 million senior revolving credit facility agreement (Senior Credit Agreement) dated November 23, 2004. The amended Senior Credit Agreement provides for a borrowing base of $260 million that will be redetermined on a semi-annual basis, beginning April 1, 2006, with us and the lenders each having the right to one annual interim unscheduled redetermination, and adjusted based on our oil and gas properties, reserves, other indebtedness and other relevant factors. Upon a redetermination, we could be required to repay a portion of the bank debt.

Amounts outstanding under the Senior Credit Agreement bear interest at a specified margin over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.00% to 0.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Senior Credit Agreement are secured by first priority liens on substantially all of our assets, including equity interest in our subsidiaries. Amounts drawn on the facility mature on July 28, 2009.

The Senior Credit Agreement requires us to maintain certain financial covenants pertaining to minimum working capital levels, minimum coverage of interest expense, and a maximum leverage ratio. We may not permit our ratio of reserves to total debt to be less than 1.5 to 1.0. We may not permit our ratio of total debt to EBITDA (as defined in the debt agreement) for the period of four fiscal quarters immediately preceding the date of redetermination for which financial statements are available to be greater than 4.0 to 1.0. In addition, we are subject to covenants limiting dividends, and other restricted payments, transactions with affiliates, incurrence of debt, changing of control, asset sales,

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and liens on properties. At December 31, 2005, we are in compliance with all of our debt covenants under the Senior Credit Agreement.

In connection with the North Louisiana Acquisitions and effective as of January 27, 2006, we amended our Senior Credit Agreement dated as of July 28, 2005, as amended. Pursuant to the amendment, the maximum credit amounts were increased to $600 million and the borrowing base was increased to $400 million. The execution of the amendment by the lenders also constituted a waiver by the lenders permitting the North Louisiana Acquisitions and provided for the repurchase of approximately 3.3 million shares of our common stock from EnCap Investments, L.P. and certain of its affiliates.

Second Lien Term Loan Facility

A second lien term loan facility (Term Loan) in the amount of $50 million was provided by BNP Paribas and a group of lenders. On July 28, 2005, our Term Loan was amended to increase the amount that we are permitted to borrow there under from $50 million to $150 million.

At the closing of the Mission merger, we had drawn $75 million under the Term Loan. By September 30, 2005 we had exercised our option to borrow an additional $75 million, applying the proceeds to outstanding borrowings under the Senior Credit Agreement. Amounts repaid under the Term Loan may not be re-borrowed. Amounts outstanding under the Term Loan bear interest at a specified margin over the LIBOR rate of 4.50% for Eurodollar loans or at specified margins over the ABR rate of 3.50% for ABR loans. Borrowings under the Term Loan are secured by second priority liens on all of the assets (including equity interests) that secure borrowings under the Senior Credit Agreement. We are subject to certain financial covenants pertaining to minimum asset coverage ratio and maximum leverage ratio. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We are obligated to repay 1% per annum of the original principal balance beginning on July 28, 2006, with the remaining 96% of the original principal balance due and payable on July 28, 2010. At December 31, 2005, we are in compliance with all of our debt covenants under the Term Loan.

Also in connection with the North Louisiana Acquisitions and effective as of January 27, 2006, we amended our Term Loan dated as of July 28, 2005, as amended. Pursuant to the amendment, the maximum commitment amount thereunder was increased from $200 million to $300 million. Also under the amendment, an incremental commitment in the amount of $75 million which could be borrowed in connection with the North Louisiana Acquisitions was made available to us. The execution of the amendment by the lenders also constituted a waiver by the lenders permitting the North Louisiana Acquisitions and provided for the EnCap Transaction. All of our subsidiaries are parties to the supplement and amendment documents and have pledged all or substantially all of their assets as collateral for the loans.

9 7/8% Senior Notes

On April 8, 2004, Mission issued $130.0 million of its 9 7/8% senior notes due 2011 (the Notes) which were guaranteed on an unsubordinated, unsecured basis by all of its current subsidiaries. Interest on the Notes is payable semi-annually, on each April 1 and October 1, commencing on October 1, 2004. In conjunction with the Mission merger, we have assumed these Notes. Following the effectiveness of the Mission merger, we entered into a supplemental indenture (Indenture) whereby we assumed, and subsidiaries guaranteed, all the obligations of Mission under the Notes as set forth in the original indenture between Mission and the Bank of New York dated April 8, 2004. The Notes are subordinate to the Senior Credit Agreement and Term Loan. At any time on or after April 9, 2005 and prior to April 9, 2008, we may redeem up to 35% of the aggregate principal amount of the Notes, using the net proceeds of equity offerings, at a redemption price equal to 109.875% of the principal amount of the Notes, plus accrued and unpaid interest. On or after April 9, 2008, we may redeem all or a portion of the Notes at redemption prices ranging from 100% in 2010 to approximately 105% in 2008. In November 2005, we acquired at market price $5.5 million face amount of the Notes from an investor and subsequently retired those Notes.

Upon the effectiveness of the Mission merger, a change of control (as defined in the Indenture) occurred and pursuant to the Indenture, we were obligated to make a change of control offer (as defined in the Indenture) within 30 days after the change of control. The offer price was 101% of the aggregate principal amount of the Notes, plus accrued and unpaid interest and was made to all noteholders. The offer has expired; and one noteholder with a $10,000 principal balance Note accepted our offer.

As discussed above, on or after April 9, 2008, we may redeem all or a portion of the Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest, if redeemed during the twelve-month period beginning on April 9 of the years indicated below:

Year	**Percentage**
2008	104.94%
2009	102.47%
2010	100.00%

The purchase method of accounting for the Mission merger required that we record the assets and liabilities acquired at fair value. The Notes were trading at a premium on the merger date; therefore, an $11.1 million premium on the Notes was recorded to reflect the merger date fair value of the Notes on Petrohawk s balance sheet. The premium will be amortized over the life of the Notes using the effective interest method. The amortization resulted in a $0.6 million reduction of interest expense for the year ended December 31, 2005. Future amortization will result in a reduction of interest expense.

Off-Balance Sheet Arrangements

At December 31, 2005 and December 31, 2004, we did not have any off-balance sheet arrangements.

Plan of Operation for 2006

On an annual basis, we generally fund most of our capital and exploration activities, excluding major oil and gas property acquisitions, with cash generated from operations and, when necessary, our senior revolving credit facility. We budget these capital expenditures based on our projected cash flows for the year. We have budgeted $210 million in capital expenditures for 2006.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States of America. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See Results of Operations above and Item 8. Consolidated Financial Statements and Supplementary Data Note 1, *Organization and Summary of Significant Events and Accounting Policies*, for a discussion of additional accounting policies and estimates made by management.

Oil and Gas Activities

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available successful efforts and full cost. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. The successful efforts method requires exploration costs to be expensed as they are incurred while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas

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properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using period-end prices and costs and a 10% discount rate.

Full Cost Method

We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into a cost center (the amortization base). Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our oil and gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of total proved reserves. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas activities.

Proved Oil and Gas Reserves

Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of oil and gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

Our estimated proved reserves for the years ended December 31, 2005 and 2003 were prepared by Netherland, Sewell, an independent oil and gas reservoir engineering consulting firm. The December 31, 2004 proved reserve estimates were prepared by Netherland Sewell with the exception of 26.2 Bcfe of proved reserves associated with royalty interest properties acquired from Wynn-Crosby and subsequently sold on February 25, 2005 which were not part of Netherland Sewell s report. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Consolidated Financial Statements and Supplementary Data, *Supplemental Oil and Gas Disclosure*.

Depreciation, Depletion and Amortization

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test write-down.

Full Cost Ceiling Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, it would reduce earnings and impact stockholders equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a write-down if prices increase subsequent to the end of a quarter in which a write-down might otherwise be required. If oil and gas prices decline, even if for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our oil and gas properties could occur in the future.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

The accounting for future abandonment costs changed on January 1, 2003 with the adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations*. This new standard requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

Holding all other factors constant, if our estimate of future abandonment and development costs is revised upward, earnings would decrease due to higher depreciation, depletion and amortization (DD&A) expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense.

Allocation of Purchase Price in Business Combinations

As part of our business strategy, we actively pursue the acquisition of oil and gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Effective January 1, 2002, we adopted SFAS No. 142, *Goodwill and Other Intangible Assets*, under which goodwill is no longer subject to amortization. Rather, goodwill of each reporting unit is tested for impairment on an annual basis, or more frequently if an event occurs or circumstances change that would reduce the fair value of the reporting unit below its carrying amount. In making this assessment, we rely on a number of factors including operating results, economic projections and anticipated cash flows. As there are inherent uncertainties related to these factors and our judgment in applying them to the analysis of goodwill impairment, there is risk that the carrying value of our goodwill may be overstated. If it is overstated, such impairment would reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill.

Accounting for Derivative Instruments and Hedging Activities

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and gas production. We generally hedge a substantial, but varying, portion of our anticipated oil and gas production for the next 12-36 months. We do not use derivative instruments for trading purposes. We have elected not to apply hedge accounting to our derivative contracts, which would potentially allow us to not record the change in fair value of our derivative contracts in the statement of operations. We carry our derivatives at fair value on our consolidated balance sheet, with the changes in the fair value included in our statement of operations in the period in which the change occurs. Our results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivative contracts.

In determining the amounts to be recorded, we are required to estimate the fair values of the derivative instruments. We currently use an independent, third-party service to estimate the fair value of our derivative contracts. The estimates of fair value that we receive are based upon various factors that include closing prices on the NYMEX, volatility and the time value of options. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates.

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Comparison of Results of Operations

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

We had a net loss of $16.6 million for the year ended December 31, 2005 compared to net income of $8.1 million for 2004. The net loss in 2005 resulted from a pre-tax loss on derivative contracts of $100.4 million.

The following table summarizes key items of comparison and their related increase (decrease) for the year ended December 31 for the periods indicated.

In Thousands	Years Ended December 31, 2005	2004	Increase (Decrease)
Net (loss) income	$ (16,634)	$ 8,117	$ (24,751)
Oil and gas sales	258,039	33,577	224,462
Production expenses:			
Lease operating	30,784	5,540	25,244
Workover and other	3,265	294	2,971
Taxes other than income	18,497	2,319	16,178
Gathering, transportation and other	2,030	26	2,004
General and administrative:			
General and administrative	21,214	7,802	13,412
Stock-based compensation	3,820	3,529	291
Depletion Full cost	72,716	9,117	63,599
Depreciation Other	666	114	552
Accretion expense	1,157	137	1,020
Net (loss) gain on derivative contracts	(100,380)	7,441	(107,821)
Interest expense and other (1)	(29,207)	(2,894)	(26,313)
Income tax benefit (provision)	9,063	(1,129)	10,192
Production:			
Natural Gas Mmcf	20,219	3,569	16,650
Crude Oil Mbbl	1,555	244	1,311
Natural Gas Equivalent Mmcfe	29,549	5,030	24,519
Average price per unit (2):			
Gas price per Mcf	$ 8.46	$ 6.53	$ 1.93
Oil price per Bbl	55.62	40.71	14.91
Equivalent per Mcfe	8.73	6.61	2.12
Average cost per Mcfe:			
Production expenses:			
Lease operating	1.04	1.10	(0.06)
Workover and other	0.11	0.06	0.05
Taxes other than income	0.63	0.46	0.17
Gathering, transportation and other	0.07	0.01	0.06
General and administrative expense:			
General and administrative	0.72	1.55	(0.83)
Stock-based compensation	0.13	0.70	(0.57)
Depletion expense	2.46	1.81	0.65

(1)

Includes $2.9 million non cash charge related to the modification of the Term Loan during the third quarter of 2005.

(2) *Amounts exclude the impact of cash paid on settled contracts as we did not elect to apply hedge accounting.*

For the year ended December 31, 2005, oil and gas sales increased $224.5 million, from the same period in 2004, to $258.0 million. The increase for the year was primarily due to the increase in production of 24,519 Mmcfe, of which 8,798 Mmcfe related to the acquisition of Mission and 1,907 Mmcfe related to the acquisition of Proton in 2005. The remaining increase in volumes was due to the inclusion of a full year of production for Wynn-Crosby as well as our increased drilling success. Higher commodity prices led to an approximate $62.6 million increase in revenues from the prior year as our realized average price per Mcfe increased $2.12 in 2005 to $8.73 from $6.61 in 2004. Prices continued to be strong in 2005 due to a number of factors including Hurricanes Rita and Katrina, inventory storage levels and continued supply concerns due to both domestic and global events.

Lease operating expenses increased $25.2 million for the year ended December 31, 2005 as compared to the same period in 2004. The increase was primarily due to the acquisition of Wynn-Crosby in November of 2004 and Mission and Proton during 2005, as well as an increase in overall activity in 2005. We drilled 146 gross wells in 2005 compared to only 71 gross wells in 2004. On a per unit basis, lease operating expenses decreased 5% from $1.10 per Mcfe in 2004 to $1.04 per Mcfe in 2005 primarily as our increase in production of 24,519 Mcfe offset the increase in overall costs.

Workover and other expense increased $3.0 million for the year ended December 31, 2005 as compared to the same period in 2004. The increase was primarily due to the increase in major maintenance activities as commodity prices have remained high as well as the acquisitions of Wynn-Crosby in 2004 and Proton and Mission in 2005. On a per unit basis, workover and other expense increased $0.05 per Mcfe to $0.11 per Mcfe in 2005 due to a number of higher cost activities that were undertaken by us based on the current period price environment.

Taxes other than income increased $16.2 million for the year ended December 31, 2005 as compared to the same period in 2004. A significant component of such increase related to production taxes which are generally assessed as a percentage of gross oil and/or natural gas sales. In general, production taxes increase as revenue and production increase.

Gathering, transportation and other expense increased $2.0 million for the year ended December 31, 2005 as compared to the same prior in 2004, due to the acquisition of Wynn-Crosby and Mission.

General and administrative expense for the twelve months ended December 31, 2005 increased $13.4 million to $21.2 million compared to $7.8 million in the same period in 2004. This increase was directly related to our continued growth over the past two years. Office expenses increased with our relocation of the corporate office to Houston, Texas and the subsequent expansion of the office following the July 2005 acquisition of Mission. Salaries and benefits increased with the addition of new staff and annual salary increases for existing employees. Overall headcount increased to 154 full time employees in 2005 as compared to 43 in 2004, driven by the decision to bring the previously outsourced accounting function back in house as well as the recent acquisition activity. On an Mcfe basis, general and administrative costs decreased $0.83 per Mcfe in 2005 to $0.72 per Mcfe as compared to $1.55 per Mcfe in 2004 due to the synergies achieved from the Wynn-Crosby, Proton and Mission acquisitions. For the twelve months ended December 31, 2005, stock-based compensation was $3.8 million, an increase of $0.3 million over prior year.

Accretion expense increased $1.0 million from the same period in 2004 to $1.2 million for the year ended December 31, 2005. The increase was due to the inclusion of a full year of accretion expense for Wynn-Crosby which increased the overall liability $10.8 million in 2004 and the acquisitions of Proton and Mission in 2005 which increased the liability $38.5 million in 2005.

Depletion expense increased $63.6 million from the same period in 2004 to $72.7 million for the year ended December 31, 2005. Depletion for oil and gas properties is calculated using the unit of production method, which essentially depletes the capitalized costs associated with the evaluated properties based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. On a per unit basis, depletion expense increased 36% from $1.81 to $2.46. This increase was due to our acquisition and divestiture activities in 2005.

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on oil and gas production. At December 31, 2005, we had a $3.5 million derivative asset, $1.3 million of which was classified as current, and an $86.8 million derivative liability, $51.1 million of which was classified as current. The change in the unrealized fair value of these derivative positions was included in earnings along with the realized losses incurred. We recorded a net derivative loss of $100.4 million for the year ended December 31, 2005 compared to a net gain of $7.4 million at December 31, 2004.

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Interest expense and other increased $26.3 million for the year ended December 31, 2005 compared to the same period in 2004. This increase was primarily due to the assumption of $130 million of Mission s 9 7/8% notes due 2011, the expensing of debt issue costs, a one-time payment made upon conversion of the $35 million PHAWK Note during the second quarter of 2005 and to the $55 million increase in our senior revolving credit facility and the $100 million increase in our second lien term loan facility, most of which were used to fund the Mission acquisition.

Income tax benefit increased $10.2 million. This increase was primarily due to the increase in our pre-tax loss from prior year. Our 2005 effective tax rate was 35.3% compared to 12.2% in 2004. The difference in the rate is the result of a valuation allowance reversal of $2.4 million in 2004.

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Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

We had net income of $8.1 million for the year ended December 31, 2004 compared to $1.0 million for 2003. The $425 million acquisition of Wynn-Crosby and the $60 million recapitalization by PHAWK, LLC of the Company, as well as the $1.83 per Mcfe increase in our realized equivalent average price for the year were the primary reasons for the increase in net income.

The following table summarizes key items of comparison and their related increase (decrease) for the year ended December 31 for the periods indicated.

	Years Ended December 31,		**Increase**
In Thousands	**2004**	**2003**	**(Decrease)**
Net income	$ 8,117	$ 968	$ 7,149
Oil and gas sales	33,577	12,925	20,652
Production expenses:			
Lease operating	5,540	2,516	3,024
Workover and other	294	25	269
Taxes other than income	2,319	875	1,444
Gathering, transportation and other	26	46	(20)
General and administrative:			
General and administrative	7,802	2,678	5,124
Stock-based compensation	3,529	252	3,277
Full cost ceiling impairment		129	(129)
Depletion Full cost	9,117	4,671	4,446
Depreciation Other	114	187	(73)
Accretion expense	137	50	87
Net gain (loss) on derivative contracts	7,441		7,441
Interest expense and other	(2,894)	(506)	(2,388)
Income tax provision	(1,129)	(24)	(1,105)
Production:			
Natural Gas Mmcf	3,569	1,859	1,710
Crude Oil Mbbl	244	129	115
Natural Gas Equivalent Mmcfe	5,030	2,632	2,398
Average price per unit (1):			
Gas price per Mcf	$ 6.53	$ 4.71	$ 1.82
Oil price per Bbl	40.71	27.36	13.35
Equivalent per Mcfe	6.61	4.78	1.83
Average cost per Mcfe:			
Lease operating expense	1.10	0.96	0.14
Workover and other	0.06	0.01	0.05
Taxes other than income	0.46	0.33	0.13
Gathering, transportation and other	0.01	0.02	(0.01)
General and administrative expense:			
General and administrative	1.55	1.02	0.53
Stock-based compensation	0.70	0.10	0.60
Depletion expense	1.81	1.77	0.04

[(1)] *2004 amounts exclude the impact of cash paid on settled contracts as we did not elect to apply hedge accounting.*

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For the year ended December 31, 2004, oil and gas sales increased $20.7 million, from the same period in 2003, to $33.6 million. The increase for the year was primarily due to the increase in volumes of approximately 2,398 Mmcfe that was comprised of a 684 Mmcfe increase for Petrohawk and a 1,714 Mmcfe increase due to the acquisition of Wynn-Crosby. Higher commodity prices led to an approximate $9.2 million increase in revenues from the prior year as our realized average price per Mcfe increased $1.83 in 2004 to $6.61 from $4.78 in 2003. Continued lower natural gas storage levels, supply uncertainty due to global events and a weaker U.S. dollar, favorably impacted crude oil prices again in 2004.

Lease operating expenses increased $3.0 million for the year ended December 31, 2004 as compared to the same period in 2003. The increase was primarily due to the acquisition of Wynn-Crosby and an increase in overall activity in 2004 as we drilled 71 gross wells in 2004 compared to only 28 gross wells in 2003, as well as higher operating costs associated with our offshore Louisiana properties and other recently drilled wells in Kansas and Oklahoma. On a per unit basis, lease operating expenses increased 15% from $0.96 per Mcfe in 2003 to $1.10 per Mcfe in 2004 due to an increase in industry-wide service costs associated with the overall increase in commodity prices.

Taxes other than income increased $1.4 million for the year ended December 31, 2004 as compared to the same period in 2003 due to higher oil and gas revenues. Production taxes are generally assessed as a percentage of gross oil and/or natural gas sales.

General and administrative expense for the twelve months ended December 31, 2004 increased $5.1 million to $7.8 million compared to the same period in 2003. This increase was the result of a number of items including an increase in bonuses, our recapitalization by PHAWK, LLC, the resulting transition of our headquarters from Tulsa, Oklahoma to Houston, Texas, as well as an increase in salaries and benefits due to the increase in headcount. At December 31, 2004, we had 43 full-time employees as compared to 12 full-time employees at December 31, 2003.

Stock-based compensation expense was $3.5 million for the year ended December 31, 2004, an increase of $3.3 million over the same period in 2003. This increase is due to the $1.8 million recorded during the second quarter of 2004 as a result of the modification of stock options held by certain former employees, as well as $1.7 million recognized for current year stock option issuances under the fair value accounting method that we follow.

Depletion expense increased $4.4 million from the same period in 2003 to $9.1 million for the year ended December 31, 2004. Depletion for oil and gas properties is calculated using the unit of production method, which essentially depletes the capitalized costs associated with the evaluated properties based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. On a per unit basis, depletion expense remained relatively flat increasing 2.2% from $1.77 to $1.81 per Mcfe.

Interest expense and other increased $2.4 million for the year ended December 31, 2004 compared to the same period 2003. This increase is primarily due to the issuance of the $35 million 8% subordinated convertible note payable issued in our recapitalization by PHAWK, LLC and the $210 million debt that was incurred in association with the acquisition of Wynn-Crosby.

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on oil and gas production. At December 31, 2004, we had a $8.3 million derivative receivable and a $2.1 million derivative liability. The change in the unrealized fair value of these derivative positions are included in earnings along with all realized gains and losses. We had recorded a net derivative gain of $7.4 million for the year ended December 31, 2004.

Income tax expense increased approximately $1.1 million from prior year. This increase is primarily due to the increase in net income offset by valuation allowance adjustments of $2.4 million.

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Related Party Transactions

On May 25, 2004, PHAWK, LLC (formerly known as Petrohawk Energy, LLC) (PHAWK), which is owned by affiliates of EnCap Investments, L.P., Liberty Energy Holdings LLC, Floyd C. Wilson and other members of our management, purchased a controlling interest in us for $60 million in cash. The $60 million investment was structured as the purchase by PHAWK of 7.576 million shares of our common stock for $25 million, a $35 million five year 8% subordinated note convertible into approximately 8.75 million shares of our common stock and warrants to purchase 5 million shares of our common stock at a price of $3.30 per share (after giving effect to a one-for-two reverse split of our common stock implemented in May 2004). In connection with the investment by PHAWK, Mr. Wilson was named our Chairman, President and Chief Executive Officer, our board of directors and other management was changed, and our corporate offices were relocated from Tulsa, Oklahoma to Houston, Texas. Also, at our annual stockholders meeting held July 15, 2004, our stockholders approved changing our name to Petrohawk Energy Corporation (from Beta Oil & Gas, Inc.), reincorporating the Company in Delaware, and the adoption of new stock option plans.

On June 30, 2005, we entered into an agreement with PHAWK to convert the $35 million note payable to PHAWK to common stock as stipulated in the original agreement. The original agreement contained a provision providing for conversion into 8.75 million shares of Petrohawk common stock at any time after May 25, 2006. In consideration of the early conversion, we agreed to make a payment of $2.4 million, which represented the interest payable on the note through May 25, 2006, discounted at 10%. In conjunction with the conversion, we expensed $1.1 million of net debt issuance costs that were being amortized over the remaining life of the note. These charges are reflected in interest expense and other on the consolidated statement of operations.

A Special Committee of one disinterested director was formed by our board of directors to evaluate the transaction. On June 30, 2005, the Special Committee approved the transaction.

On August 11, 2004 we purchased working interests in certain oil and gas properties and various other assets from PHAWK for $8.5 million. The effective date of the acquisition was June 1, 2004. Since the Company and PHAWK were under common control, the assets were recorded at the net book value of PHAWK at the time of the sale. The purchase price exceeded the net book value by approximately $5.6 million. The excess was reflected as a return of capital to PHAWK on the consolidated statement of operations.

A special committee of one disinterested director was formed by our board of directors to evaluate, negotiate and complete the purchase. The Special Committee hired an independent reservoir engineering firm to provide a reserve evaluation and engaged an independent financial advisor to evaluate the fairness, from a financial point of view, to us. The independent financial advisor rendered a fairness opinion to the Special Committee.

Recently Issued Accounting Standards

In March 2005, the Financial Accounting Standard Board (FASB) issued FASB Interpretation (FIN) No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations*. This Interpretation clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside our control. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. This Interpretation is intended to provide more information about long-lived assets, future cash outflows for these obligations and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The adoption of this Interpretation did not materially impact our operating results, financial position or cash flows.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)). SFAS 123(R) is a revision of SFAS No. 123, *Accounting for Stock Based Compensation* (SFAS 123), and supersedes APB 25, *Accounting for Stock Issued to Employees*. Among other items, SFAS 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. We currently utilize the Black-Scholes option pricing model to measure the fair value of stock options granted and plans to continue to use that model upon adoption of SFAS 123(R). We are in the process of finalizing the adoption of SFAS 123(R) and does not expect it to materially impact our future operating results.

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In March 2005, the SEC issued SAB 107 on SFAS No. 123(R) (SAB 107). SAB 107 reinforces the flexibility allowed by SFAS 123(R) to choose an option pricing model, provides guidance on when it would be appropriate to rely exclusively on either historical or implied volatility in estimating expected volatility and provided examples and simplified approaches to determining the expected term. In April 2005, the SEC extended the date by which companies are required to adopt SFAS 123(R) from the first reporting period beginning on or after June 15, 2005 to the first reporting period of the first fiscal year beginning on or after June 15, 2005.

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Oil and gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business.

Our operating revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for gas and, to a lesser extent, oil. Declines in oil and gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil and gas prices may also reduce the amount of oil and gas that we can produce economically. Historically, oil and gas prices and markets have been volatile, with prices fluctuating widely and they are likely to continue to be volatile. Prices for oil and gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- The domestic and foreign supply of oil and gas;
- The level of consumer product demand;
- Weather conditions;
- Political conditions in oil producing regions, including the Middle East;
- The ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- The price of foreign imports;
- Actions of governmental authorities;
- Domestic and foreign governmental regulations;
- The price, availability and acceptance of alternative fuels; and
- Overall economic conditions.

These factors make it impossible to predict with any certainty the future prices of oil and gas.

We use hedges to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. For the twelve months ended December 31, 2005, we had hedges covering 13,867,500 Mmbtus of natural gas and 1,044,200 Bbls of crude oil as compared to 705,000 Mmbtus and 27,500 Bbls, respectively, in 2004.

Derivative Instruments and Hedging Activity

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on oil and gas production. Under collar arrangements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. Under price swaps, we receive a fixed price on a notional quantity of oil and gas in exchange for paying a variable price based on a market-based index, such as NYMEX oil and gas futures.

At December 31, 2005, we had 48 open positions: 20 natural gas price collar arrangements, one natural gas price swap arrangement, four natural gas put options, one crude oil price swap arrangement and 22 crude oil collar arrangements. We elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, record the net change in the mark-to-market valuation of these derivative contracts in the consolidated statement of operations. At December 31, 2005, we had a $3.5 million derivative asset, $1.3 million of which is classified as current, and a $86.8 million derivative liability, $51.1 million of which is classified as current. The weighted average of the forward strip prices used to value the derivative liability were $63.14 per barrel of oil and $10.41 per mcf of natural gas. On the July 28, 2005 merger date, we acquired a $29.4 million derivative liability from Mission. At December 31, 2005, the fair value of the derivatives acquired from Mission was $22.7 million.

We recorded a net derivative loss of $100.4 million for the year ended December 31, 2005.

At December 31, 2004, we had 90 open positions: 35 natural gas price collar arrangements, 12 natural gas price swap arrangements, seven natural gas put options, nine crude oil price swap arrangements and 27 crude oil collar arrangements. During 2004, we elected not to designate any positions as cash flow hedges for accounting purposes.

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At December 31, 2004, we had an $8.3 million derivative receivable and a $2.1 million derivative liability. In addition, we recorded a net derivative gain of $7.4 million for the year ended December 31, 2004.

For the year ended December 31, 2003, we designated our derivative positions as hedges against the variability in cash flows associated with the forecasted sale of future oil and gas accounted for under the guidelines stipulated by SFAS 133. At December 31, 2003, we had no open positions but we recognized a net $0.6 million loss on derivative contracts for the year ended December 31, 2003.

Natural Gas

At December 31, 2005, we had the following natural gas costless collar positions:

		Contract Price per Mmbtu Collars					
		Floors			Ceilings		
Period	Volume in Mmbtu s	Price / Price Range		Weighted Average Price	Price / Price Range		Weighted Average Price
January 2006 - December 2006	15,175,000	$5.00	$6.26	$ 5.79	$7.08	$10.87	$ 9.05
January 2007 - December 2007	6,530,000	5.30	6.00	5.69	7.12	15.35	11.72
January 2008 - December 2008	3,600,000	5.00	5.15	5.05	6.45	6.71	6.53

At December 31, 2005, we had the following natural gas swap position:

Contract Price per Mmbtu Swaps		
Period	Volume in Mmbtu s	Weighted Average Price
January 2007 December 2007	1,200,000	$ 6.06

At December 31, 2005, we had the following natural gas put options:

Contract Price per Mmbtu Floors		
Period	Volume in Mmbtu s	Weighted Average Price
January 2006 December 2006	5,400,000	$ 8.00
January 2007 December 2007	3,600,000	8.00

During the fourth quarter of 2005, we entered into three natural gas put option contracts covering 5,400,000 Mmbtus of anticipated production in 2006 and one natural gas put option contract covering 3,600,000 Mmbtus of anticipated production in 2007. These natural gas put option contracts contain deferred premiums that will be paid as the contracts expire. We have recorded a deferred premium liability of $4.1 million as of December 31, 2005 based on a weighted average deferred premium of $0.24 per Mmbtu in 2006 and $0.78 per Mmbtu in 2007.

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Crude Oil

At December 31, 2005, we had the following crude oil costless collar positions:

		Contract Price per Bbl Collars					
		Floors			Ceilings		
Period	Volume in Bbls	Price / Price Range		Weighted Average Price	Price / Price Range		Weighted Average Price
January 2006 - December 2006	1,338,750	$ 26.03	$45.48	$ 38.17	$ 30.15	$62.70	$ 50.78
January 2007 - December 2007	240,000	35.00	36.00	35.30	43.20	45.75	43.97
January 2008 - December 2008	60,000		34.00	34.00		45.30	45.30

At December 31, 2005, we had the following crude oil swap position:

Contract Price per Bbl Swaps		
Period	Volume in Bbls	Weighted Average Price
January 2008 December 2008	144,000	$ 38.10

For more information, refer to Item 8. Consolidated Financial Statements and Supplementary Data, Note 7 *Derivative and Hedging Activities*.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of senior revolving credit facility and the second lien term loan facility approximates its carrying value because the debt carries interest rates that approximate current market rates. The 9 7/8% notes were trading at $103.25 at year end 2005 and would have a fair value of $128.5 million at December 31, 2005, as compared to the book value of $124.5 million, excluding the unamortized premium.

Interest Sensitivity

Our senior revolving credit facility and our second lien term loan facility are based on variable interest rates that approximate current market rates. A one percent increase or decrease in these rates would result in a $14.3 million change in our interest expense over the life of our long-term debt. Should interest rates increase we believe we have adequate capital resources to meet the cash requirements of the Company.

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, including the Company s Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Petrohawk Energy Corporation s internal control over financial reporting was effective as of December 31, 2005. We excluded the acquisition of Mission Resources Corporation (Mission) from our assessment of internal control over financial reporting as of December 31, 2005 because Mission was acquired in a business combination on July 28, 2005. Mission s total assets and revenues constitute 57 and 33 percent, respectively, of the related consolidated financial statements of the Company as of and for the year ended December 31, 2005

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2005, was audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Floyd C. Wilson	/s/ Shane M. Bayless
Floyd C. Wilson Chairman of the Board, President and Chief Executive Officer	Shane M. Bayless Executive Vice President, Chief Financial Officer and Treasurer

Houston, Texas
March 13, 2006

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Petrohawk Energy Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of Petrohawk Energy Corporation and subsidiaries (formerly Beta Oil and Gas, Inc.) (the Company) as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders equity, cash flows, and comprehensive income (loss) for each of the two years in the period ended December 31, 2005. We also have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting (Report of Management), that the Company maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Report of Management, management excluded from their assessment the internal control over financial reporting at Mission Resources Corporation and subsidiaries (Mission), which was acquired on July 28, 2005 and whose consolidated financial statements reflect total assets and revenues constituting 57 and 33 percent, respectively, of the related consolidated financial statements of the Company as of and for the year ended December 31, 2005. Accordingly, our audit did not include the internal control over financial reporting at Mission. The Company s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on these financial statements, an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audit of financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of

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the Treadway Commission. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 13, 2006

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders
of Beta Oil & Gas, Inc.

We have audited the accompanying consolidated statements of operations, changes in stockholders equity and cash flows for the year ended December 31, 2003. 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 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 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated results of operations and cash flows of Beta Oil & Gas, Inc. for the year ended December 31, 2003, in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 1 and 5 to the consolidated financial statements, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, *Asset Retirement Obligations*. In addition, as also discussed in Note 1, effective January 1, 2003, the Company adopted, prospectively, the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation.*

/s/ Ernst & Young LLP
Tulsa, Oklahoma
March 19, 2004

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PETROHAWK ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	Years Ended December 31,		
	2005	**2004**	**2003**
Operating revenues:			
Oil and gas sales	$ 258,039	$ 33,577	$ 12,925
Operating expenses:			
Production expenses:			
Lease operating	30,784	5,540	2,516
Workover and other	3,265	294	25
Taxes other than income	18,497	2,319	875
Gathering, transportation and other	2,030	26	46
General and administrative:			
General and administrative	21,214	7,802	2,678
Stock-based compensation	3,820	3,529	252
Full cost ceiling impairment			129
Depletion, depreciation and amortization	73,382	9,231	4,858
Accretion expense	1,157	137	50
Total operating expenses	154,149	28,878	11,429
Income from operations	103,890	4,699	1,496
Other income (expense):			
Net (loss) gain on derivative contracts	(100,380)	7,441	
Interest expense and other	(29,207)	(2,894)	(506)
Total other income (expense):	(129,587)	4,547	(506)
(Loss) income before income taxes	(25,697)	9,246	990
Income tax benefit (provision)	9,063	(1,129)	(24)
Net (loss) income before cumulative effect of accounting change	(16,634)	8,117	966
Cumulative effect of accounting change			2
Net (loss) income	(16,634)	8,117	968
Preferred dividends	(440)	(445)	(447)
Net (loss) income applicable to common shareholders	$ (17,074)	$ 7,672	$ 521
(Loss) Earnings Per Share of Common Stock:			
Basic	$ (0.31)	$ 0.71	$ 0.08
Diluted	$ (0.31)	$ 0.36	$ 0.08
Weighted average shares outstanding:			

Basic	54,752	10,808	6,216
Diluted	54,752	25,690	6,253

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

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PETROHAWK ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2005	December 31, 2004
Current assets:		
Cash and cash equivalents	$ 12,911	$ 5,660
Accounts receivable	68,087	23,151
Deferred income taxes	18,304	
Receivables from price risk management activities	1,286	4,973
Prepaid expenses and other	5,393	2,238
Total current assets	105,981	36,022
Oil and gas properties (full cost method):		
Evaluated properties	1,096,810	484,233
Unevaluated properties	162,133	48,840
Total gross oil and gas properties	1,258,943	533,073
Less accumulated depletion and depreciation	(121,456)	(48,740)
Net oil and gas properties	1,137,487	484,333
Other operating property and equipment		
Gas gathering system and equipment	1,508	1,504
Other	3,555	1,261
Total gross other operating property and equipment	5,063	2,765
Less accumulated depreciation	(1,600)	(934)
Net other operating property and equipment	3,463	1,831
Other noncurrent assets		
Goodwill	132,029	
Debt issuance costs, net of amortization	1,969	3,875
Receivables from price risk management activities	2,252	3,363
Deferred income taxes		981
Other	26,993	3,794
Total assets	$ 1,410,174	$ 534,199

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

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PETROHAWK ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS (Continued)
(In thousands, except share and per share data)

	December 31, 2005	December 31, 2004
Current liabilities:		
Accounts payable and accrued liabilities	$ 90,017	$ 24,676
Liabilities from price risk management activities	51,081	1,990
Current portion of long-term debt	2,788	500
Total current liabilities	143,886	27,166
Long-term debt	495,801	239,500
Liabilities from price risk management activities	35,695	67
Asset retirement obligations	50,133	12,726
Deferred income taxes	153,155	
Other noncurrent liabilities	5,046	7,649
Commitments and contingencies		
Stockholders equity:		
Convertible Preferred stock: 5,000,000 shares of $.001 par value authorized; 593,271 and 598,271 shares issued and outstanding at December 31, 2005 and 2004; liquidation value at December 31, 2005 and 2004 of $5.5 million	1	1
Common stock: 125,000,000 and 75,000,000 shares of $.001 par value authorized at December 31, 2005 and 2004; 73,566,117 and 39,788,238 shares issued and outstanding at December 31, 2005 and 2004	74	40
Additional paid-in capital	558,452	262,045
Treasury stock, at cost, 8,382 shares reacquired at December 31, 2005 and 2004	(36)	(36)
Accumulated deficit	(32,033)	(14,959)
Total stockholders equity	526,458	247,091
Total liabilities and stockholders equity	$ 1,410,174	$ 534,199

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

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PETROHAWK ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In thousands)

	Preferred		Common		Additional Paid in	Treasury	Accumulated Comprehensive	Accumulated	Total Stockholders
	Shares	Amount	Shares	Amount	Capital	Stock	Income	Deficit	Equity
Balance at January 1, 2003	604	$ 1	6,223	$ 6	$ 51,923	$ (28)	$ (702)	$ (23,152)	$ 28,048
Equity compensation vesting					252				252
Treasury stock acquired						(8)			(8)
Offering costs					(245)				(245)
Preferred stock dividends								(447)	(447)
Comprehensive Income							702		702
Net income								968	968
Balances at December 31, 2003	604	$ 1	6,223	$ 6	$ 51,930	$ (36)	$	$ (22,631)	$ 29,270
Equity compensation vesting			179		2,131				2,131
Warrants					2,027				2,027
Preferred stock acquired	(6)				(55)				(55)
Preferred stock private placement	2,581	3			199,997				200,000
Preferred stock private placement conversion to common stock	(2,581)	(3)	25,806	26	(23)				
Return of Capital to PHAWK, LLC					(3,550)				(3,550)
Offering costs					(15,466)				(15,466)
Preferred stock dividends								(445)	(445)
Common stock issuances			7,580	8	25,054				25,062
Net income								8,117	8,117
Balances at December 31, 2004	598	$ 1	39,788	$ 40	$ 262,045	$ (36)	$	$ (14,959)	$ 247,091

Equity compensation vesting					3,449				3,449
Common stock issued for purchase of Mission Resourses			19,565	19	209,909				209,928
Conversion of LLC Note			8,750	9	34,991				35,000
Warrants excercised			1,645	2	(2)				
Equity related to Mission s vested options					27,302				27,302
Preferred stock dividends								(440)	(440)
Repurchase of preferred stock	(5)				(46)				(46)
Common stock issuances			3,818	4	12,517				12,521
Tax benefit from exercise of stock options					8,287				8,287
Net loss								(16,634)	(16,634)
Balances at December 31, 2005	593	$ 1	73,566	$ 74	$ 558,452	$ (36)	$	$ (32,033)	$ 526,458

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

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PETROHAWK ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31, 2005	2004	2003
Cash flows from operating activities:			
Net (loss) income	$ (16,634)	$ 8,117	$ 968
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	73,382	9,231	4,858
Amortization of debt issue costs	1,839	214	
Full cost ceiling impairment			129
Deferred income tax (provision) benefit	(9,533)	1,153	
Stock-based compensation	3,820	3,529	252
Accretion expense	1,157	137	50
Net unrealized loss (gain) on mark-to-market derivative contracts	64,180	(8,603)	
Net realized loss on mark-to-market derivative contracts acquired	28,931		
Other	(1,903)	59	(1)
Change in assets and liabilities, net of acquisitions:			
Accounts receivable	(17,472)	3,266	(356)
Prepaid expenses and other	114	(815)	(79)
Accounts payable and accrued liabilities	8,298	1,655	(28)
Other non-current assets	(733)		
Net cash provided by operating activities	135,446	17,943	5,793
Cash flows from investing activities:			
Oil and gas expenditures	(121,041)	(12,842)	(4,043)
Acquisition of Mission, net of cash acquired of $48,359	(96,545)		
Acquisition of Wynn-Crosby, net of cash acquired of $2,584		(384,521)	
Acquisition of Proton, net of cash acquired of $870	(52,625)		
Acquisition of oil and gas properties from PHAWK, LLC		(2,636)	
Proceeds received from sale of oil and gas properties	88,900	839	549
Gas gathering system and equipment expenditures	(2,298)	(905)	(52)
Other	(22,500)	(416)	
Net cash used in investing activities	(206,109)	(400,481)	(3,546)
Cash flows from financing activities:			
Proceeds from exercise of options	12,055		
Proceeds from issuance of common stock and warrants		25,629	
Proceeds from issuance of subordinated convertible note payable		35,000	
Debt issue costs		(4,089)	
Return of capital to PHAWK, LLC		(5,684)	

Proceeds from borrowings	375,000	220,000	
Repayment of borrowings	(279,510)	(68,689)	(364)
Proceeds from Series B preferred stock private placement		200,000	
Net realized loss on mark-to-market derivative contracts acquired	(28,931)		
Offering Costs		(15,466)	(245)
Dividends paid on Preferred Series A	(331)	(558)	(447)
Other	(369)	(55)	(8)
Net cash provided by (used in) financing activities	77,914	386,088	(1,064)
Net increase in cash and cash equivalents	7,251	3,550	1,183
Cash and cash equivalents:			
Beginning of period	5,660	2,110	927
End of period	$ 12,911	$ 5,660	$ 2,110

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

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PETROHAWK ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)

	Years Ended December 31,		
	2005	**2004**	**2003**
Comprehensive income (loss):			
Net income (loss)	$ (16,634)	$ 8,117	$ 968
Other comprehensive income:			
Reclassification adjustment for settled contracts (net of income taxes)			1,337
Unrealized loss on qualifying cash flow hedges (net of income taxes)			(635)
Total comprehensive income (loss)	$ (16,634)	$ 8,117	$ 1,670

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

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PETROHAWK ENERGY CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Events and Accounting Policies

Basis of Presentation and Principles of Consolidation

Petrohawk Energy Corporation (Petrohawk or the Company) is an independent oil and gas company engaged in the acquisition, development, production and exploration of oil and gas properties located in North America. The Company operates in one segment, oil and gas exploration and exploitation, almost exclusively within the continental United States. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. All significant intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation.

On May 18, 2004, the Company s Board of Directors approved a one-for-two reverse stock split that was effective May 26, 2004. The reverse stock split was implemented to effect the conditional approval by the NASDAQ National Market of the Company s listing application, which was later formally approved. Share and per share data (except par value) for all periods presented have been restated to reflect the reverse stock split.

Information regarding reserves, working interest, acreage and well head counts, to the extent disclosed, are unaudited.

Use of Estimates

The preparation of the Company s consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company s management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. The estimates include oil and gas reserve quantities which form the basis for the calculation of amortization of oil and gas properties. Management emphasizes that reserve estimates are inherently imprecise and that estimates of more recent reserve discoveries are more imprecise than those for properties with long production histories. Actual results could materially differ from these estimates.

Cash and Cash Equivalents

The Company considers short-term investments with an original maturity of less than three months to be cash equivalents.

Allowance for Doubtful Accounts

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectibility and establishes or adjusts the allowance as necessary using the specific identification method. There is no significant allowance for doubtful accounts at December 31, 2005 and December 31, 2004.

Oil and Gas Properties

The Company accounts for its oil and gas producing activities using the full cost method of accounting as prescribed by the Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general corporate costs are expensed as incurred. Sales or other dispositions of oil and gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of proved oil and gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We review our unevaluated properties at the end of each quarter to determine whether the costs incurred should be classified to the full cost pool and thereby subject to amortization.

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Property, Plant and Equipment Other than Oil and Gas Properties

Other operating property and equipment are stated at the lower of cost or fair market value. Provision for depreciation and amortization on property and equipment is calculated using the straight-line method over the estimated useful lives (ranging from 3 to 10 years) of the respective assets. The cost of normal maintenance and repairs is charged to operating expense as incurred. Material expenditures, which increase the life of an asset, are capitalized and depreciated over the estimated remaining useful life of the asset. The cost of properties sold, or otherwise disposed of, and the related accumulated depreciation or amortization are removed from the accounts and any gains or losses are reflected in current operations.

Impairment of Long-Lived Assets

In the event that facts and circumstances indicate that the costs of long-lived assets, other than oil and gas properties, may be impaired, an evaluation of recoverability would be performed. If an evaluation is required, the estimated future undiscounted cash flows associated with the asset would be compared to the asset s carrying amount to determine if a write-down to market value or discounted cash flow value is required. Impairment of oil and gas properties is evaluated subject to the full cost ceiling as described under the Oil and Gas Properties section above.

Revenue Recognition

The Company recognizes oil and gas sales upon delivery to the purchaser. Under the sales method, the Company and other joint owners may sell more or less than their entitled share of the natural gas volume produced. Should the Company s excess sales of natural gas exceed its share of estimated remaining recoverable reserves, a liability is recorded by the Company and revenue is deferred.

Concentrations of Credit Risk

The Company operates a substantial portion of its oil and gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company s joint interest partners consist primarily of independent oil and gas producers. If the oil and gas exploration and production industry in general were adversely affected, the ability of the Company s joint interest partners to reimburse the Company could be adversely affected. The purchasers of the Company s oil and gas production consist primarily of independent marketers, major oil and gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts. In 2005, the Company had one individual purchaser that accounted for approximately 12% of the Company s total sales. In 2004, the Company had no individual customers accounting for more than 10% of total sales. In 2003, approximately 53% of the Company s total sales were made to three individual customers. The Company does not believe the loss of any one of its purchasers would materially affect the Company s ability to sell the oil and gas it produces. The Company believes other purchasers are available in the Company s areas of operations.

Price Risk Management Activities

On January 1, 2001, the Company adopted Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging* Activities, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133* and as amended by SFAS No. 149, *Amendment of Statement No. 133 on Derivative Instruments and Hedging Activities*. From time to time, the Company may hedge a portion of its forecasted oil and gas production. Derivative contracts entered into by the Company have consisted of cash flow hedge transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. As of December 31, 2005 and 2004, and for the years then ended, the Company has elected to not designate any of its positions for hedge accounting. Accordingly, all derivatives are recorded in current earnings as a component of other income and expenses on the statement of operations. In 2003 the Company designated derivatives as cash flow hedges and applied hedge accounting.

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Income Taxes

The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Asset Retirement Obligation

In August 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). The Company was required to adopt this new standard beginning January 1, 2003. SFAS 143 requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Upon adoption, the Company recorded an asset retirement obligation to reflect the Company s legal obligations related to future plugging and abandonment of its oil and gas wells. The Company estimated the expected cash flow associated with the obligation and discounted the amount using a credit-adjusted, risk-free interest rate. The transition adjustment resulting from the adoption of SFAS 143 was reported as a cumulative effect of a change in accounting principle. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and gas wells as these obligations are incurred.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in the acquisition. SFAS 142 requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change could potentially result in an impairment.

The impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. The reporting unit used for testing will be the entire company. The fair value of the Company is determined and compared to the book value. If the fair value is less than the book value (including goodwill) then goodwill is reduced to its implied fair value and the amount of the write-down is charged to earnings.

The fair value will be based on estimates of future net cash flows from proved reserves and from future exploration for and development of unproved reserves. Downward revisions of estimated reserves or production, increases in estimated future costs or decreases in oil and gas prices could lead to an impairment of all or a portion of goodwill in future periods.

Fair Value of Financial Instruments

The estimated fair values for financial instruments under FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of revolving credit facility and the term facility approximates its carrying value because the debt carries interest rates that approximate current market rates. The 9 7/8% notes were trading at $103.25 at year end 2005 and would have a fair value of $128.5 million at December 31, 2005, as compared to the book value of $124.5 million, including the unamortized premium.

We account for our derivative activities under the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS NOs. 137, 138 and 149. This statement, as amended, establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 7, *Derivative and Hedging Activities* for more details.

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Stock-Based Compensation

On January 1, 2003, the Company adopted SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123) and related interpretations in accounting for its employee and director stock options and applies the fair value based method of accounting to such options. Under SFAS 123, the fair value of each option granted is estimated on the date of grant using a option-pricing model such as the Black-Scholes model. Under SFAS No. 148 *Accounting for Stock-Based Compensation Transition and Disclosure* , an amendment to SFAS 123, certain transitional alternatives were available for a voluntary change to the fair value based method of accounting for stock-based employee compensation if adopted in a fiscal year beginning before December 16, 2003. The Company adopted SFAS 123 prospectively, using the fair value recognition method to all employee and director awards granted, modified or settled after January 1, 2003. Prior to the adoption, the Company elected to follow Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and related interpretations in accounting for its employee stock options. However, as required by SFAS 123, the Company disclosed on a pro forma basis the impact of the fair value accounting for employee stock options. Transactions in equity instruments with non-employees for goods or services have been accounted for using the fair value method as prescribed by SFAS 123. Since the Company adopted the fair value recognition provisions of SFAS 123 prospectively for all employee awards granted, modified or settled after January 1, 2003, the cost related to stock-based compensation included in the determination of income for the year ended December 31, 2003, is less than that which would have been recognized if the fair value method had been applied to all awards since the original effective date of SFAS 123. Awards granted vest over a period ranging from one to three years; therefore, some grants made before January 1, 2003 vested in later periods and would represent costs in those periods. For the years ended December 31, 2005 and 2004, these costs were accounted for based on the requirements of SFAS 123.

The fair value of each option grant is calculated on the date of grant using the Black-Scholes option pricing model. The following table illustrates the approximated pro forma effect on net income (loss) and earnings (loss) per share as if the fair value based method had been applied to all outstanding and unvested awards in each period (in thousands).

	Years Ended December 31,	
	2004	**2003**
Net income (loss) applicable to common shareholders as reported	$ 7,672	$ 521
Add: Stock-based compensation expense included in reported net income (loss), net of tax	2,201	252
Deduct: Total stock-based compensation expense determined under fair value method for all awards, net of tax	(2,330)	(407)
Pro forma net income (loss) applicable to common shareholders	$ 7,543	$ 366
Income (loss) per share:		
Basic as reported	$ 0.71	$ 0.08
Basic pro forma	$ 0.70	$ 0.06
Diluted as reported	$ 0.36	$ 0.08
Diluted pro forma	$ 0.35	$ 0.06

There were no costs accounted for under APB 25 during the year ended December 31, 2005.

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The assumptions used in calculating the fair value of the Company s stock-based compensation is disclosed in the following table:

	Years Ended December 31,		
	2005	2004	2003
Weighted average value per option granted during the period [(1)]	$ 2.31	$ 3.77	$ 1.43
Assumptions [(2)]:			
Stock price volatility	29.3%	73.9%	61.3%
Risk free rate of return	3.6%	3.0%	3.2%
Expected term	3 years	3 years	5 years

(1) *For purposes of estimating the fair value of options on their date of grant, the Company used the Black-Scholes option pricing model.*

(2) *The Company does not pay dividends on its common stock.*

Earnings per Share

Basic EPS is calculated by dividing the income or loss available (or attributable) to common shareholders by the weighted average number of shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

401(k) Plan

The Company sponsors a 401(k) tax deferred savings plan, whereby the Company matches a portion of employees contributions in cash. Participation in the plan is voluntary and all regular employees of the Company are eligible to participate. The Company charged to expense plan contributions of $0.7 million in 2005, $0.3 million in 2004 and less than $0.1 million in 2003. The Company began matching employee contributions dollar-for-dollar on the first 10% in September 2004. Prior contributions were matched dollar-for-dollar on the first 3% of an employee s pretax earnings.

Recently Issued Accounting Pronouncements

In March 2005, the FASB issued FASB Interpretation (FIN) No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations*. This Interpretation clarifies the definition and treatment of conditional asset retirement obligations as discussed in SFAS 143. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the Company. FIN 47 states that a Company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. This Interpretation is intended to provide more information about long-lived assets, future cash outflows for these obligations and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The adoption of this Interpretation did not materially impact the Company s operating results, financial position or cash flows.

In December 2004, the FASB issued SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)). SFAS 123(R) is a revision of SFAS No. 123, *Accounting for Stock Based Compensation* (SFAS 123), and supersedes APB

25, *Accounting for Stock Issued to Employees*. Among other items, SFAS 123(R) eliminates the use of APB 25 and the intrinsic value method of accounting and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. The Company currently utilizes the Black-Scholes option pricing model to measure the fair value of stock options granted and plans to continue to use that model upon adoption of SFAS 123(R). The Company is in the process of finalizing the adoption of SFAS 123(R) and does not expect it to materially impact the Company s future operating results.

In March 2005, the SEC issued SAB 107 on SFAS No. 123(R) (SAB 107). SAB 107 reinforces the flexibility allowed by SFAS 123(R) to choose an option pricing model, provides guidance on when it would be appropriate to rely exclusively on either historical or implied volatility in estimating expected volatility and provided examples and simplified approaches to determining the expected term. In April 2005, the SEC extended the date by which companies are required to adopt SFAS 123(R) from the first reporting period beginning on or after June 15, 2005 to the first reporting period of the first fiscal year beginning on or after June 15, 2005.

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2. ACQUISITIONS AND DIVESTITURES

Mission Resources Corporation

On April 4, 2005, the Company, and Mission Resources Corporation (Mission), a Delaware corporation, announced the execution of an Agreement and Plan of Merger, dated as of April 3, 2005, as amended through June 8, 2005, (the Merger Agreement) pursuant to which Mission agreed to merge with and into the Company in a two-step merger transaction. This transaction was consummated on July 28, 2005 when Petrohawk Acquisition Corporation, the Company s wholly owned subsidiary, merged with and into Mission, and Mission was subsequently merged with and into the Company (the two mergers, collectively the Merger), pursuant to the Merger Agreement. A copy of the Merger Agreement has been filed as Annex A to the Company s Registration Statement on Form S-4/A with the Securities and Exchange Commission on June 22, 2005. This transaction was consistent with management s goals of acquiring properties within the Company s core operating areas that have a significant proved reserve component and which management believes have additional development and exploration opportunities.

Total consideration for the shares of Mission common stock was comprised of 60.1% Company common stock and 39.9% cash. Accordingly, consideration paid to Mission stockholders in the Merger consisted of approximately $139.5 million in cash and approximately 19.565 million shares of the Company s common stock. In addition, all outstanding options to purchase Mission common stock were converted into options to purchase Petrohawk common stock using the exchange ratio of 0.7641 shares of Petrohawk common stock per share of Mission common stock underlying each option. The Company assumed Mission s long-term debt of approximately $184 million.

The Merger was accounted for using the purchase method of accounting under the accounting standards established in SFAS No. 141, *Business Combinations* and No. 142, *Goodwill and Other Intangible Assets (SFAS 142)*. As a result, the assets and liabilities of Mission were included in the Company s September 30, 2005 consolidated balance sheet. The Company reflected the results of operations of Mission beginning July 28, 2005. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at July 28, 2005, which primarily consisted of oil and gas properties of $606.7 million, derivative liabilities of $29.4 million, asset retirement obligations of $37.7 million, a net deferred tax liability of $134.8 million, and goodwill of $138.9 million. The deferred tax liability recognizes the difference between the historical tax basis of Mission s assets and the acquisition cost recorded for book purposes. The recorded book value of the oil and gas properties was increased and goodwill was recorded to recognize this tax basis differential. The purchase price allocation is preliminary and subject to change as additional information becomes available. Management does not expect to make any material changes to the original purchase price allocation.

Wynn-Crosby Transaction

On November 23, 2004, the Company acquired Wynn-Crosby Energy, Inc. and eight of the limited partnerships it managed for a purchase price of approximately $425 million after closing adjustments (the Acquisition or Wynn-Crosby). The transaction was funded with proceeds from a $200 million private equity placement, $210 million in borrowings from its commercial bank group, and cash.

Pro Forma for Mission Resources and Wynn-Crosby

The Company s unaudited pro forma results are presented below for the years ended December 31, 2005 and 2004. The unaudited pro forma results have been prepared to illustrate the approximated pro forma effects on the Company s results of operations under the purchase method of accounting as if the Company had acquired Mission Resources Corporation and Wynn-Crosby, Inc. on January 1, 2004. The unaudited pro forma results do not purport to represent what the results of operations would actually have been if the acquisition had in fact occurred on such date or to project the Company s results of operations for any future date or period.

	Years Ended December 31,	
	2005 (Unaudited)	2004 (Unaudited)
	(In thousands)	
Pro forma:		
Oil and gas sales	$ 359,261	$ 275,351
Net (loss) income available to common stockholders	(18,796)	16,865
Basic earnings per share	$ (0.31)	$ 0.54
Diluted earnings per share	$ (0.31)	$ 0.36

Proton Oil & Gas Corporation

On February 25, 2005, the Company acquired the stock of Proton Oil & Gas Corporation (Proton) for $53 million in cash. This privately negotiated transaction had an effective date of January 1, 2005. The properties acquired were located in South Louisiana and South Texas.

The acquisition of Proton was accounted for using the purchase method of accounting. As a result, the assets and liabilities of Proton were included in the Company s March 31, 2005 consolidated balance sheet. The transaction had an effective date of January 1, 2005 and closed on February 25, 2005. As such, the Company reflected the results of operations of Proton beginning February 25, 2005. The Company recorded a purchase price of approximately $80.4 million of which $26.0 million reflected a non-cash item pertaining to the deferred income taxes attributable to the differences between the tax basis and the fair value of the acquired oil and gas properties. Substantially all of the $80.4 million was allocated to oil and gas properties. The purchase price allocation is preliminary and subject to change as additional information becomes available. Management does not expect to make any material changes to the original purchase price.

Sale of Royalty Interest Properties

On February 25, 2005, the Company completed the disposition of certain royalty interest properties previously acquired from Wynn-Crosby Energy, Inc. to Noble Royalties, Inc. (Noble) d/b/a Brown Drake Royalties for approximately $80 million in cash. The transaction had an effective date of January 1, 2005.

PHAWK, LLC Transaction

On August 11, 2004, the Company acquired from PHAWK, LLC (formerly known as Petrohawk Energy, LLC) (PHAWK) certain oil and gas properties in the Breton Sound area, Plaquemines Parish, Louisiana and in the West Broussard field in Lafayette Parish, Louisiana. The purchase price for all of the proved reserves, seismic data, undeveloped acreage, pipelines, production facility and other assets was $8.5 million. The effective date of the acquisition was June 1, 2004 and the effects of this transaction were first reported in results for the quarter ended September 30, 2004. Refer to Note 10, *Related Party Transactions*, for more details.

Recapitalization by PHAWK, LLC

On May 25, 2004, PHAWK, LLC, which is owned by affiliates of EnCap Investments, L.P., Liberty Energy Holdings LLC, Floyd C. Wilson and other members of the Company s management, recapitalized the Company with $60 million in cash. The $60 million investment was structured as the purchase by PHAWK of 7.576 million new shares of common stock for $25 million, a $35 million five year 8% subordinated note convertible into approximately 8.75 million shares of

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common stock at a conversion price of $4.00 per share and warrants to purchase 5.0 million shares of common stock at a price of $3.30 per share. At the annual stockholders meeting held July 15, 2004, the stockholders approved changing the name of the Company to Petrohawk Energy Corporation (from Beta Oil & Gas, Inc.), reincorporating the Company in Delaware, and the adoption of new incentive plans. On June 30, 2005, the Company entered into an agreement with PHAWK, LLC to convert the PHAWK Note to common stock as stipulated in the original agreement. Refer to Note 10, *Related Party Transactions*, for more details.

3. OIL AND GAS PROPERTIES

Oil and gas properties as of December 31, 2005 and 2004 consisted of the following:

	December 31,	
	2005	2004
	(in thousands)	
Subjection to depletion	$ 1,096,810	$ 484,233
Not subject to depletion:		
Exploration wells in progress	14,006	161
Other capital costs:		
Incurred in 2005	113,215	
Incurred in 2004 and prior	34,912	48,679
Total not subject to depletion	162,133	48,840
Gross oil and gas properties	1,258,943	533,073
Less accumulated depletion	(121,456)	(48,740)
Net oil and gas properties	$ 1,137,487	$ 484,333

4. LONG-TERM DEBT

Long-term debt as of December 31, 2005 and 2004 consisted of the following:

	December 31,	
	2005	2004
	(in thousands)	
Senior revolving credit facility	$ 210,000	$ 155,000
Second lien term loan facility *(1)*	148,500	49,500
9 7/8% senior notes (2)	134,484	
Subordinated convertible note payable *(3)*		35,000
Deferred premiums on derivatives *(4)*	2,817	
	$ 495,801	$ 239,500

(1) *The Company s second lien term loan facility was amended July 28, 2005 to increase the amount the Company was*

permitted to borrow from $50 million to $150 million. $1.5 million of the total $150 million facility has been classified as current on the December 31, 2005 balance sheet and $0.5 million of the $50 million facility was classified as current on the December 31, 2004 balance sheet.

(2) *Amount includes $10.0 million premium recorded by the Company in conjunction with the assumption of $130 million face value of 9 7/8% notes payable from Mission. See Note 2, Acquisitions and Divestitures for more details.*

(3) *Converted into 8.75 million shares of common stock on June 30, 2005.*

(4) *Amount excludes $1.3 million of deferred premiums on*

derivatives which has been classified as current on the December 31, 2005 balance sheet.

Senior Revolving Credit Facility

The Company entered into a new senior revolving credit facility with BNP Paribas as the lead bank and administrative agent on November 23, 2004, in connection with the acquisition of Wynn Crosby. The $400 million revolving credit facility had an initial borrowing base of $200 million and a threshold amount of $180 million. On April 1, 2005, the borrowing base under the facility was changed to $185 million with a threshold amount of $175 million.

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In connection with the Merger with Mission, the Company amended and restated its $400 million senior revolving credit agreement (Senior Credit Agreement) dated November 23, 2004. The amended Senior Credit Agreement provides for an increased borrowing base of $260 million that will be redetermined on a semi-annual basis, beginning April 1, 2006, with the Company and the lenders each having the right to one annual interim unscheduled redetermination, and adjusted based on the Company s oil and gas properties, reserves, other indebtedness and other relevant factors. Upon a redetermination, the Company could be required to repay a portion of the bank debt. Amounts outstanding under the Senior Credit Agreement bear interest at a specified margin over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.00% to 0.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Senior Credit Agreement are secured by first priority liens on substantially all of the Company s assets, including equity interest in the Company s subsidiaries. Amounts drawn on the facility mature on July 28, 2009.

The Senior Credit Agreement requires the Company to maintain certain financial covenants pertaining to minimum working capital levels, minimum coverage of interest expense, and a maximum leverage ratio. The Company may not permit its ratio of reserves to total debt to be less than 1.5 to 1.0 after March 31, 2005. The Company may not permit its ratio of total debt to EBITDA (as defined in the debt agreement) for the period of four fiscal quarters immediately preceding the date of redetermination for which financial statements are available to be greater than 4.0 to 1.0. In addition, the Company is subject to covenants limiting dividends, and other restricted payments, transactions with affiliates, incurrence of debt, changing of control, asset sales, and liens on properties. At December 31, 2005, the Company is in compliance with all of its debt covenants under the Senior Credit Agreement.

In connection with the acquisition of all of the issued and outstanding common stock of Winwell Resources, Inc. and the acquisition of certain oil and gas assets from Redley Company, the Company amended the Senior Credit Agreement. Refer to Note 12, *Subsequent Events*, for more details.

Second Lien Term Loan Facility

A second lien facility (Term Loan) in the amount of $50 million was provided by BNP Paribas and a group of lenders which is due on February 25, 2009. Borrowings under the Term Loan will initially bear interest at LIBOR plus 4.00%, increasing 0.25% on a quarterly basis thereafter, subject to a ceiling of LIBOR plus 5.00%. Borrowings under the Term Loan facility are secured by a second priority lien on substantially all of the assets securing the Senior Credit Agreement. The Company is subject to certain financial covenants pertaining to minimum asset coverage ratio and a maximum leverage ratio as discussed above under the revolving credit facility. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties.

On July 28, 2005, the Company s Term Loan was amended to increase the amount that the Company is permitted to borrow thereunder from $50 million to $150 million.

At the closing of the Merger, the Company had drawn $75 million under the Term Loan. By September 30, 2005 the Company had exercised its option to borrow an additional $75 million, applying the proceeds to outstanding borrowings under the Senior Credit Agreement. Amounts repaid under the Term Loan may not be re-borrowed. Amounts outstanding under the Term Loan bear interest at a specified margin over the LIBOR rate of 4.50% for Eurodollar loans or at specified margins over the ABR rate of 3.50% for ABR loans. The Company is obligated to repay 1% per annum of the original principal balance beginning on July 28, 2006, with the remaining 96% of the original principal balance due and payable on July 28, 2010. At December 31, 2005, the Company is in compliance with all of its debt covenants under the Term Loan.

In connection with the acquisition of all of the issued and outstanding common stock of Winwell Resources, Inc. and the acquisition of certain oil and gas assets from Redley Company, the Company amended the Term Loan. Refer to Note 12, *Subsequent Events*, for more details.

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9 7/8% Senior Notes

On April 8, 2004, Mission issued $130.0 million of its 9 7/8% senior notes due 2011 (the Notes) which are guaranteed on an unsubordinated, unsecured basis by all of its current subsidiaries. Interest on the notes is payable semi-annually, on each April 1 and October 1, commencing on October 1, 2004. In conjunction with the acquisition of Mission, the Company has assumed these notes. Following the effectiveness of the Merger, the Company entered into a supplemental indenture (Indenture) whereby the Company assumed, and subsidiaries guaranteed, all the obligations of Mission under the Notes as set forth in the original indenture between Mission and the Bank of New York dated April 8, 2004.

The Notes were issued in the face amount of $130 million and are guaranteed on an unsubordinated basis by all of the Company s current subsidiaries. The Notes are subordinate to the Senior Credit Facility and Term Loan. At any time on or after April 9, 2005 and prior to April 9, 2008, the Company may redeem up to 35% of the aggregate principal amount of the Notes, using the net proceeds of equity offerings, at a redemption price equal to 109.875% of the principal amount of the Notes, plus accrued and unpaid interest. On or after April 9, 2008, the Company may redeem all or a portion of the Notes at redemption prices ranging from 100% in 2010 to approximately 105% in 2008. In November 2005, the Company acquired, at market price, $5.5 million face amount of the Notes from an investor. The Company retired those Notes and recognized a gain on extinguishment of debt of approximately $0.1 million.

Upon the effectiveness of the Merger, a Change of Control (as defined in the Indenture) occurred and pursuant to the Indenture, the Company was obligated to make a Change of Control Offer (as defined in the Indenture) within 30 days after the change of control. The offer price is 101% of the aggregate principal amount of the Notes, plus accrued and unpaid interest and must be made to all noteholders. The offer has expired, with one noteholder with a $10,000 principal balance Note accepting the Company s offer.

As discussed above, on or after April 9, 2008, the Company may redeem all or a portion of the 9 7/8% Notes at the redemption prices (expressed as percentages of principal amount) set forth below plus accrued and unpaid interest, if redeemed during the twelve-month period beginning on April 9 of the years indicated below:

Year	**Percentage**
2008	104.94%
2009	102.47%
2010	100.00%

The purchase method of accounting for the Merger required that the Company record the assets and liabilities acquired at fair value. The Notes were trading at a premium on the merger date, therefore, a $11.1 million premium on the Notes was recorded to reflect the merger date fair value of the Notes on Petrohawk s balance sheet. The premium will be amortized over the life of the Notes using the effective interest method. The amortization resulted in a $0.6 million reduction of interest expense for the year ended December 31, 2005. Future amortization will result in a reduction of interest expense.

The Notes contain covenants that, subject to certain exceptions and qualifications, limit the Company s ability and the ability of certain of its subsidiaries to incur or guarantee additional indebtedness, issue certain types of equity securities, transfer or sale assets, or pay dividends. Additionally, transactions with affiliates, selling stock of a subsidiary, merging or consolidating are subject to qualifications.

Subordinated Convertible Note Payable

On May 25, 2004, in connection with the recapitalization of the Company by PHAWK, LLC, the Company issued a $35 million five-year unsecured subordinated convertible note payable to PHAWK, LLC (the PHAWK Note). The PHAWK Note bore interest at 8%, was payable quarterly until maturity and was convertible after two years into 8.75 million shares of common stock at a conversion price of $4.00 per share. On June 30, 2005, the Company entered into an agreement with PHAWK, LLC to convert the PHAWK Note to common stock as stipulated in the original agreement. The original agreement contained a provision providing for conversion into 8.75 million shares of Petrohawk common stock at any time after May 25, 2006. In conjunction with the early conversion, the Company made payment of $2.4 million, which represented the interest that would have been payable on the PHAWK Note through May 25, 2006, discounted at 10%.

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Aggregate maturities required on long-term debt at December 31, 2005 are due in future years as follows (amounts in thousands):

2006	$ 2,788
2007	4,317
2008	1,500
2009	211,500
2010	144,000
Thereafter	124,484
Total	$ 488,589

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt.

In conjunction with the acquisition of Mission, the Company modified its Term Loan. This modification increased the Company s borrowing capacity from $50 million to $150 million and was appropriately treated as an extinguishment of debt for accounting purposes. This treatment resulted in a charge of approximately $2.9 million in the third quarter of 2005. This charge is included in the interest expense and other line of the consolidated statement of operations.

During the second quarter of 2005, in conjunction with the conversion of the PHAWK Note, the Company expensed $1.1 million of net debt issuance costs that were being amortized over the remaining life of the note. This amount is included in interest expense and other on the consolidated statement of operations.

At December 31, 2005, the Company has approximately $2.0 million of net debt issuance costs that are being amortized over the lives of the respective debt.

5. ASSET RETIREMENT OBLIGATION

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, the Company records a liability (an asset retirement obligation or ARO) on the consolidated balance sheet and capitalizes the asset retirement cost in oil and gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for the company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

The Company recorded the following activity related to the ARO liability for the years ended December 31, 2005 and 2004 (in thousands):

Beginning balance as of January 1, 2004	$ 1,235
Liabilities settled and divested	(12)
Additions	541
Acquisition of Wynn-Crosby [(1)]	10,825
Accretion expense	137
Liability for asset retirement obligation as of December 31, 2004	$ 12,726
Beginning balance	$ 12,726
Liabilities settled and divested	(1,562)
Additions	455

Acquisition of Mission and Proton[(1)]	38,473
Accretion expense	1,157
Liability for asset retirement obligation as of December 31, 2005	$ 51,249

(1) *Refer to Note 2 Acquisitions and Divestitures for more details on these acquisitions.*

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The Company currently plans to plug approximately 40 gross wells in 2006. Accordingly, the Company has classified $1.1 million of the overall $51.2 million liability as a current liability in accounts payable and accrued liabilities at December 31, 2005.

6. COMMITMENTS, CONTINGENCIES AND LITIGATION

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of our business. All known liabilities are accrued based on management s best estimate of the potential loss. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, the Company s management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company s consolidated financial position or cash flow.

A lawsuit has been filed by Andrew A. Roth (Mr. Roth) against the Company, as a nominal defendant, certain of our directors and certain of our current and former stockholders, including PHAWK, LLC, alleging violations of Section 16(b) of the Exchange Act of 1934, as amended. The lawsuit seeks recovery, on behalf of the Company, of alleged short-swing profits of at least $6,465,000. Mr. Roth filed the lawsuit in the United States District Court for the Southern District of New York on October 31, 2005 as *Andrew A. Roth derivatively on behalf of Petrohawk Energy Corporation v. PHAWK, LLC, et. al.,* and the case was assigned Civil Case Number: 05 CV 9247. Pursuant to an August 1, 2005 demand letter from Mr. Roth, an independent committee of the board of directors of the Company investigated Mr. Roth s claims prior to the filing of the lawsuit and concluded they had no merit. The Company is monitoring developments in the matter with legal counsel. The Company does not believe this litigation shall have a material effect on the Company s financial position or results of operations, should the plaintiff s allegations be found to be accurate.

The Company has established reserves for certain legal proceedings. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. Management believes these reserves to be adequate, and does not expect the Company to incur additional losses with respect to those matters in which reserves have been established. However, future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued. While the outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the consolidated results of operations, financial position or cash flows of the Company.

Prior to the acquisition of Mission Resources (Mission) by Petrohawk, Mission entered into agreements with a surety company and other third parties. All parties involved agreed to be jointly and severally liable to the surety company for certain liabilities arising under the agreement and limited to approximately $35 million. As of December 31, 2005 there have been no payments made as a result of this agreement.

Lease Commitments

The Company leases corporate office space in Houston, Texas, certain vehicles, machinery and equipment under long-term operating leases. Rent expense was $0.7 million, $0.3 million, and $0.2 million for the years ended December 31, 2005, 2004, and 2003, respectively. Future minimum lease payments for all non-cancelable operating leases are as follows (in thousands):

2006	$ 2,196
2007	1,554
2008	1,336
2009	632
2010	122
Thereafter	
Total	$ 5,840

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7. DERIVATIVE AND HEDGING ACTIVITIES

Periodically, the Company enters into derivative commodity instruments to hedge its exposure to price fluctuations on oil and gas production. Under collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index price falls below the floor price, the counterparty pays the Company. Under price swaps, the Company receives a fixed price on a notional quantity of oil and gas in exchange for paying a variable price based on a market-based index, such as NYMEX oil and gas futures.

At December 31, 2005, the Company had 48 open positions: 20 natural gas price collar arrangements, one natural gas price swap arrangement, four natural gas put options, one crude oil price swap arrangement and 22 crude oil collar arrangements. The Company elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in the consolidated statement of operations.

At December 31, 2005, the Company had a $3.5 million derivative asset, $1.3 million of which is classified as current, and an $86.8 million derivative liability, $51.1 million of which is classified as current. The weighted average of the forward strip prices used to value the derivative liability were $63.14 per barrel of oil and $10.41 per mcf of natural gas. On the July 28, 2005 merger date, the Company acquired a $29.4 million derivative liability from Mission. At December 31, 2005, the fair value of the derivatives acquired from Mission was $22.7 million.

The Company recorded a net derivative loss of $100.4 million for the year ended December 31, 2005.

At December 31, 2004, the Company had 90 open positions: 35 natural gas price collar arrangements, 12 natural gas price swap arrangements, seven natural gas put options, nine crude oil price swap arrangements and 27 crude oil collar arrangements. During 2004, the Company elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, recorded the change in mark-to-market valuation of these derivative contracts in the consolidated statement of operations.

At December 31, 2004, the Company had an $8.3 million derivative receivable and a $2.1 million derivative liability. In addition, the Company recorded a net derivative gain of $7.4 million for the year ended December 31, 2004.

For the year ended December 31, 2003, the Company designated its derivative positions as hedges against the variability in cash flows associated with the forecasted sale of future oil and gas accounted for under the guidelines stipulated by SFAS 133. At December 31, 2003, the Company had no open positions but recognized a net $0.6 million loss on derivative contracts for the year ended December 31, 2003.

Natural Gas

At December 31, 2005, the Company had the following natural gas costless collar positions:

		Contract Price per Mmbtu Collars			
		Floors		Ceilings	
Period	Volume in Mmbtu s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2006 - December 2006	15,175,000	$ 5.00-$6.26	$ 5.79	$ 7.08-$10.87	$ 9.05
January 2007 - December 2007	6,530,000	5.30 - 6.00	5.69	7.12 - 15.35	11.72
January 2008 - December 2008	3,600,000	5.00 - 5.15	5.05	6.45 - 6.71	6.53

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At December 31, 2005, the Company had the following natural gas swap position:

	Contract Price per Mmbtu	
	Swaps	
Period	Volume in Mmbtu s	Weighted Average Price
January 2007 December 2007	1,200,000	$6.06

At December 31, 2005, the Company had the following natural gas put options:

	Contract Price per Mmbtu	
	Floors	
Period	Volume in Mmbtu s	Weighted Average Price
January 2006 December 2006	5,400,000	$8.00
January 2007 December 2007	3,600,000	8.00

During the fourth quarter of 2005, the Company entered into three natural gas put option contracts covering 5,400,000 Mmbtus of anticipated production in 2006 and one natural gas put option contract covering 3,600,000 Mmbtus of anticipated production in 2007. These natural gas put option contracts contain deferred premiums that will be paid as the contracts expire. The Company has recorded a deferred premium liability of $4.1 million of long term debt (of which $1.3 million has been recorded as a current portion of long term debt) as of December 31, 2005 based on a weighted average deferred premium of $0.24 per Mmbtu in 2006 and $0.78 per Mmbtu in 2007.

Crude Oil

At December 31, 2005, the Company had the following crude oil costless collar positions:

		Contract Price per Bbl			
		Collars			
		Floors		Ceilings	
Period	Volume in Bbls	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2006 - December 2006	1,338,750	$ 26.03-$45.48	$ 38.17	$ 30.15-$62.70	$ 50.78
January 2007 - December 2007	240,000	35.00 - 36.00	35.30	43.20 - 45.75	43.97
January 2008 - December 2008	60,000	34.00	34.00	45.30	45.30

At December 31, 2005, the Company had the following crude oil swap position:

	Contract Price per Bbl	
	Swaps	
Period	Volume in Bbls	Weighted Average Price
January 2008 December 2008	144,000	$38.10

8. STOCKHOLDERS EQUITY

In conjunction with the Merger with Mission Resources, the Company filed two Registration Statements on Form S-8 and one Registration Statement on Form S-4. The first Registration Statement on Form S-8 was filed to register an additional 3.5 million shares of the Company s common stock under stock options granted pursuant to the Second Amended and Restated 2004 Employee Incentive Plan and an additional 0.2 million shares of the Company s common stock pursuant to the Second Amended and Restated 2004 Non-Employee Director Incentive Plan. The second Registration Statement on Form S-8 was filed to register approximately 3.85 million shares of common stock of the Company for issuance pursuant to employee benefit plans and nonstatutory stock option agreements of Mission which the Company agreed to assume under the term of the Merger Agreement. The Company also increased its authorized number of common shares to 125 million from 75 million. The Company registered 19.565 million shares of common stock on the Form S-4 and those shares were issued as merger consideration to holders of Mission stock.

8% Cumulative Convertible Preferred Stock

On June 29, 2001 the Company completed its Private Placement Offering of 8% cumulative convertible preferred stock and common stock purchase warrants, offered as units of one preferred share and one-half of one warrant at $9.25 per unit. Net proceeds received from the offering were approximately $5.0 million net of estimated offering expenses, including brokers commissions and other fees and expenses of $0.5 million. The Company issued 604,271 preferred shares and 151,070 warrants to purchase a like number of shares of the Company s common stock at a price equal to the offering price or $9.25 per share. Brokers were issued 29,888 non-callable warrants as part of their commission. All investors participating in the offering were accredited. The proceeds were used by the Company to help meet its capital requirements, including drilling costs and for other general corporate purposes.

The preferred shares may be converted by the holder at any time at an exchange rate of one share of the Company s common stock for each two preferred shares converted.

The preferred shares pay quarterly cash dividends commencing in the quarter that the preferred shares are issued, at an annual rate of 8% per annum, simple interest, or $0.74 per year. At December 31, 2005, the Company had $0.1 million of preferred dividends declared, which were not paid until January, 2006.

The Company has the unilateral right to redeem all or any of the outstanding preferred shares from the date of issuance but must pay a premium if redeemed within the first five years. The holders of the preferred shares will be entitled to a liquidation preference equal to the stated value of the preferred shares plus any unpaid and accrued dividends through the date of any liquidation or dissolution of the Company.

In July of 2004 and August of 2005, the Company acquired and canceled 6,000 and 5,000 shares, respectively, of the outstanding 8% cumulative convertible preferred stock.

At December 31, 2005, the liquidation preference was approximately $5.5 million. Warrants are non-transferable and may be exercised at any time through June 29, 2006.

Series B Preferred Stock

In connection with the acquisition of Wynn-Crosby on November 23, 2004, the Company issued and sold 2,580,645 shares of Series B 8% Automatically Convertible Preferred Stock for $77.50 per share, for an aggregate offering amount of approximately $200 million. The Company received approximately $185 million in net proceeds from the offering. The Series B preferred stock was offered and sold pursuant to the private placement exception from registration provided in Regulation D, Rule 506, under Section 4(2) of the Securities Act of 1933, as amended (the Act). Shares of the Series B preferred stock were offered and sold only to qualified institutional buyers as defined in Rule 144A of the Act with whom the placement agent had pre-existing relationships in reliance on applicable exemptions from registration provided under the Act. The placement agent received a commission of 6.0% in connection with the offering.

On December 31, 2004 each outstanding share of the Series B 8% Automatically Convertible Preferred Stock converted into ten shares of common stock. Accordingly, 2,580,645 shares of the Company s Series B preferred stock converted into 25,806,450 shares of common stock. In addition, the Company s Certificate of Incorporation was amended to increase the number of authorized shares of common stock from 50,000,000 to 75,000,000 effective December 31, 2004.

Treasury Stock
At December 31, 2005, the Company held 8,382 treasury shares with an average price per share of $4.35 from prior repurchase programs.

Restricted Stock
During the year ended December 31, 2005, the Company granted 55,000 shares of restricted stock to employees and 45,000 shares to directors. The employees shares vest over a three year period at a rate of one-third on the annual anniversary date of the grant, and the directors shares are further described below under *2004 Non-Employee Director Incentive Plan*. For the year ended December 31, 2005, the Company has recognized $0.8 million of non-cash restricted stock compensation expense.

Warrants and Options
The following table summarizes the number of shares reserved for the exercise of common stock purchase warrants and stock options under the Company s 1999 Amended Incentive and Non-statutory Stock Option Plan (1999 Plan), 2004 Employee Incentive Plan, Mission Resources Corporation 1994 Stock Incentive Plan, Mission Resources Corporation 1996 Stock Incentive Plan and Mission Resources Corporation 2004 Stock Incentive Plan as of December 31, 2005:

	Number of Shares	Weighted Average Exercise Price Per Share
Balance at January 1, 2004	1,716,542	$ 10.11
Granted	5,717,500	3.83
Forfeited or cancelled	(254,867)	11.90
Exercised	(178,292)	3.51
Balance at December 31, 2004	7,000,883	$ 5.08
Granted	1,404,300	$ 9.37
Forfeited or cancelled	(572,434)	15.01
Assumed in Merger with Mission	3,852,433	3.76
Exercised	(5,986,635)	3.26
Balance at December 31, 2005	5,698,547	$ 6.16
Exercisable at December 31, 2004	6,525,224	$ 4.91
Exercisable at December 31, 2005	4,417,331	$ 5.30

Warrants and options outstanding at December 31, 2005 consisted of the following:

	Outstanding Options			Exercisable Options	
Range of Exercise	Number of	Weighted Average Exercise Price	Weighted Average Remaining Contractual	Number of	Weighted Average Exercise Price

Prices Per Share		Options	per share	Life (Years)	Options	per share
$ 0.50	3.80	2,965,027	$ 3.23	3.7	2,965,027	$ 3.23
4.34	6.18	151,914	5.70	7.8	151,914	5.70
7.32	11.78	2,298,791	8.69	8.3	1,072,325	8.30
12.00	19.00	282,815	16.83	2.3	228,065	17.81

During the second quarter of 2004, and in connection with the recapitalization of the Company by PHAWK, LLC transaction, the Company issued PHAWK, LLC 5,000,000 five-year common stock purchase warrants at a price of $3.30 per share. The warrants are exercisable at any time and expire on May 25, 2009. On August 31, 2005, 2.3 million warrants were exercised. The exercise was cashless, reducing number of shares issued by the value of the $3.30 exercise price, so that the Company issued 1,645,241 shares of company stock. On July 8, 2005, shares and warrants held by PHAWK, LLC were distributed to its members, including our management.

Incentive Plans

2004 Employee Incentive Plan

Upon shareholder approval and effective July 28, 2005, the Company s Amended and Restated 2004 Employee Incentive Plan was amended and restated to be the Second Amended and Restated 2004 Employee Incentive Plan (the 2004 Plan) to increase the aggregate number of shares that can be issued under the 2004 Plan from 2,750,000 to 4,250,000. The 2004 Plan permits the Company to grant to management and other employees shares of common stock with no restrictions, shares of common stock with restrictions, and options to purchase shares of common stock.

In 2004, the Company granted stock options out of the 2004 Plan covering 717,500 shares of common stock to employees of the Company. The options will vest over a two-year period with one-third vesting on the date of grant, one-third in one year from the date of the grant and the remaining one-third in two years from the date of the grant. The options have an average exercise price of $7.53 per share and will expire ten years from the date of grant.

During fiscal 2005, the Company granted stock options covering 1,404,300 shares of common stock. The options have an average exercise price of $9.37 per share and vest over a three year period at a rate of one-third on the annual anniversary date of the grant. The options expire ten years from the grant date.

For the years ended December 31, 2005, 2004 and 2003, respectively, the Company has recognized $3.8 million, $3.5 million and $0.3 million of non-cash stock compensation expense.

At December 31, 2005, 2,094,050 options were available under the Plan for future issuance.

2004 Non-Employee Director Incentive Plan

In July 2004 the Company adopted the 2004 Non-Employee Director Incentive Plan covering 200,000 shares. The plan provides for the grant of both incentive stock options and restricted shares of the Company s stock. This plan was designed to attract and retain the services of directors. At the adoption of the plan each non-employee director received 7,500 restricted shares of the Company s common stock. Under this plan each new non-employee director will receive 7,500 shares of the Company s common stock. Additional grants of 5,000 restricted shares of the Company s common stock are expected to be issued to each non-employee director on each anniversary of his or her service. These shares vest over a six month period from the date of grant. For each of the years-ended December 31, 2005 and 2004, 45,000 shares were issued under this plan and there had been no forfeited or cancelled shares.

1999 Employee Incentive Plan

At December 31, 2005, 222,500 options from the original 1999 Employee Incentive Plan were fully vested and exercisable at a weighted average price of $4.11 per share. At December 31, 2005, there were no options available under the Plan for future issuance.

Mission Incentive Plans

In conjunction with the Merger on July 28, 2005, the Company assumed three incentive plans related to Mission Resources. The three plans were the Mission Resources Corporation 1994 Stock Incentive Plan, Mission Resources Corporation 1996 Stock Incentive Plan and Mission Resources Corporation 2004 Stock Incentive Plan. At December 31, 2005, there were 294,145 options available under the Plans for future issuance.

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9. INCOME TAXES

Income tax benefit (provision) for the indicated periods is comprised of the following:

	For the Years Ended December 31,		
	2005	2004	2003
		(in thousands)	
Current:			
Federal	$ (217)	$ 24	$ (24)
State	(253)		
	$ (470)	$ 24	$ (24)
Deferred:			
Federal	$ 9,088	$ (641)	$
State	445	(512)	
	$ 9,533	$ (1,153)	$
Total benefit (provision)	$ 9,063	$ (1,129)	$ (24)

The actual income tax benefit (provision) differs from the expected tax benefit (provision) as computed by applying the U.S. Federal corporate income tax rate of 35% for each period as follows:

	For the Years Ended December 31,		
	2005	2004	2003
		(in thousands)	
Amount of expected tax benefit (provision)	$ 8,994	$ (3,144)	$ (336)
Non-deductible expenses	(92)	(23)	3
State taxes, net	625	(338)	
Valuation allowance adjustments	(500)	2,352	333
Other	36		
Alternative minimum tax		24	(24)
	$ 9,063	$ (1,129)	$ (24)

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The components of net deferred tax assets and liabilities recognized are as follows:

	December 31, 2005	December 31, 2004
	(in thousands)	
Deferred tax assets:		
Current:		
Unrealized hedging transactions	$ 18,304	$
Deferred current tax asset	$ 18,304	$
Deferred noncurrent tax assets/(liabilities):		
Net operating loss carry-forwards	$ 45,825	$ 11,338
FAS 123 expense	2,596	1,200
Unrealized hedging transactions	12,294	
Other operating property- equipment		1,121
Other	311	
Gross deferred noncurrent tax asset	61,026	13,659
Valuation allowance	(500)	
Net deferred noncurrent tax asset	60,526	13,659
Deferred tax liability book-tax differences in property basis	(213,681)	(10,353)
Unrealized hedging transactions		(2,325)
Net noncurrent deferred tax asset/(liability)	(213,681)	(12,678)
Net long-term deferred tax asset/(liability)	$ (153,155)	$ 981

As of December 31, 2005, the Company had available, to reduce future taxable income, a U.S. federal regular net operating loss (NOL) carryforward of approximately $127.0 million, and a U.S. federal alternative minimum tax NOL carryforward of approximately $90.5 million, which expire in the years 2018 through 2024. Utilization of NOL carryforwards is subject to annual limitations due to stock ownership changes. The tax net operating loss carryforward may be limited by other factors as well. The Company also had various state NOL carryforwards totaling approximately $15.7 million (gross state NOL $38.7 million less $23.0 million valuation allowance due to corporate restructuring activities) at December 31, 2005, with varying lengths of allowable carryforward periods ranging from five to 20 years and can be used to offset future state taxable income. It is expected that these deferred tax benefits will be utilized prior to their expiration.

10. RELATED PARTY TRANSACTIONS

On May 25, 2004, PHAWK, LLC (formerly known as Petrohawk Energy, LLC) (PHAWK), which is owned by affiliates of EnCap Investments, L.P., Liberty Energy Holdings LLC, Floyd C. Wilson and other members of the Company s management, purchased a controlling interest in the Company for $60 million in cash. The $60 million investment was structured as the purchase by PHAWK of 7.576 million shares of common stock for $25 million, a $35 million five year 8% subordinated note convertible into approximately 8.75 million shares of common stock and warrants to purchase 5 million shares of common stock at a price of $3.30 per share (after giving effect to a one-for-two reverse split of the Company s common stock implemented in May 2004). In connection with the investment by PHAWK, Mr. Wilson was named Chairman, President and Chief Executive Officer, the Company s board of directors and other management was changed, and the corporate offices were relocated from Tulsa, Oklahoma to Houston, Texas. Also, at the annual stockholders meeting held July 15, 2004, the Company s stockholders approved changing the name of the company to Petrohawk Energy Corporation (from Beta Oil & Gas, Inc.), reincorporating the company in Delaware, and the adoption of new stock option plans.

On June 30, 2005, the Company entered into an agreement with PHAWK to convert the Company s $35 million note payable to PHAWK to common stock as stipulated in the original agreement. The original agreement contained a provision providing for conversion into 8.75 million shares of Petrohawk common stock at any time after May 25, 2006. In consideration of the early conversion, the Company agreed to make a payment of $2.4 million, which represented the interest payable on the note through May 25, 2006, discounted at 10%. In conjunction with the conversion, the Company expensed $1.1 million of net debt issuance costs that were being amortized over the remaining life of the note. These charges are reflected in interest expense and other on the consolidated statement of operations.

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A Special Committee of one disinterested director was formed by the Company s board of directors to evaluate the transaction. On June 30, 2005, the Special Committee approved the transaction.

On August 11, 2004 the Company purchased working interests in certain oil and gas properties and various other assets from PHAWK for $8.5 million. The effective date of the acquisition was June 1, 2004. Since the Company and PHAWK were under common control, the assets were recorded by the Company at the net book value of PHAWK at the time of the sale. The purchase price exceeded the net book value by approximately $5.6 million. The excess was reflected as a return of capital to PHAWK on the consolidated statement of operations.

A special committee of one disinterested director was formed by the Company s board of directors to evaluate, negotiate and complete the purchase. The Special Committee hired an independent reservoir engineering firm to provide a reserve evaluation and engaged an independent financial advisor to evaluate the fairness, from a financial point of view, to the Company. The independent financial advisor rendered a fairness opinion to the Special Committee.

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11. NET INCOME (LOSS) PER COMMON SHARE

The following represents the calculation of net income (loss) per common share (in thousands, except per share data):

	Years Ended December 31,		
	2005	2004	2003
Basic			
Net income (loss)	$ (16,634)	$ 8,117	$ 968
Less: preferred dividends	(440)	(445)	(447)
Net income (loss) applicable to common shareholders	$ (17,074)	$ 7,672	$ 521
Weighted average number of shares	54,752	10,808	6,216
Basic earnings (loss) per share	$ (0.31)	$ 0.71	$ 0.08
Diluted			
Net income (loss)	$ (17,074)	$ 7,672	$ 521
Plus: preferred dividends		445	
Plus: Interest on 8% subordinated convertible note payable (net of tax)		1,072	
Net income (loss) applicable to common shareholders	$ (17,074)	$ 9,189	$ 521
Weighted average number of shares	54,752	10,808	6,216
Common stock equivalent shares representing shares issuable upon exercise of stock options	Anti-dilutive	327	37
Common stock equivalent shares representing shares issuable upon exercise of warrants	Anti-dilutive	2,826	Anti-dilutive
Common stock equivalent shares representing shares as-if conversion of note payable		8,750	
Common stock equivalent shares representing shares as-if conversion of preferred shares	Anti-dilutive	2,979	Anti-dilutive
Weighted average number of shares used in calculation of diluted income (loss) per share	54,752	25,690	6,253
Diluted earnings (loss) per share	$ (0.31)	$ 0.36	$ 0.08

The following common stock equivalents were not included in the computation for diluted earnings (loss) per share because their effects would be antidilutive.

	December 31,		
Common Stock Equivalents:	**2005**	**2004**	**2003**
Options	2,779	99	647
Warrants	2,919	805	920
As-if conversion of:			
Preferred stock	294		302
	5,992	904	1,869

12. SUBSEQUENT EVENTS

Gulf of Mexico Divestiture

On February 3, 2006, the Company entered into a definitive agreement with Northstar GOM, LLC to sell substantially all of the Company s Gulf of Mexico properties for $52.5 million in cash. These properties had estimated proved reserves as of December 31, 2005 of approximately 25 Bcfe, are approximately 70% gas, 59% proved developed and 27% operated. Current production is estimated to be approximately 10 Mmcfe/d. The transaction is expected to close by March 31, 2006.

The North Louisiana Acquisitions

On January 27, 2006, the Company completed the acquisition of all of the issued and outstanding common stock of Winwell Resources, Inc. (Winwell) pursuant to a Stock Purchase Agreement with Winwell and all of its shareholders made and entered into as of December 14, 2005 (the Stock Purchase Transaction). The aggregate consideration paid in the Stock Purchase Transaction was approximately $208 million in cash after certain closing adjustments. Also on January 27, 2006, the Company completed its acquisition of assets pursuant to an Asset Purchase Agreement with Redley Company, made and entered into as of December 14, 2005, as amended, (the Asset Purchase Transaction). The aggregate consideration paid in the Asset Purchase Transaction was approximately $86 million in cash after certain closing adjustments. Through the Stock Purchase Transaction and Asset Purchase Transaction, the Company acquired oil and gas properties in the Elm Grove and Caspiana fields in North Louisiana.

The Company believes the properties present a significant, multi-year development opportunity primarily in the Cotton Valley and Hosston formations at depths of 6,500 to 10,000 feet. Successful wells in these fields generally produce for more than thirty years and have low operating costs. As part of the transactions, we assumed contracts for two operated drilling rigs. In addition, there are three to five non-operated drilling rigs working in the fields at any given time.

The Company deposited $15 million in earnest money under the terms of the Stock Purchase Transaction, and $7.5 million under the terms of the Asset Purchase Transaction. The $22.5 million deposit was included in other non-current assets at December 31, 2005. The deposit and any interest earned thereon was applied to the overall purchase price.

In connection with the transactions disclosed above and effective as of January 27, 2006, the Company amended its Amended and Restated Senior Revolving Credit Agreement dated as of July 28, 2005, as amended. Pursuant to the amendment, the maximum credit amounts were increased to $600 million and the borrowing base was increased to $400 million. The execution of the amendment by the lenders also constituted a waiver by the lenders permitting the transactions completed and discussed above and provided for the repurchase of approximately 3.3 million shares of the Company s common stock from EnCap Investments, L.P. and certain of its affiliates.

Also in connection with the transactions discussed above and effective as of January 27, 2006, the Company amended its Amended and Restated Second Lien Term Loan Agreement dated as of July 28, 2005, as amended. Pursuant to the amendment, the maximum commitment amount thereunder was increased from $200 million to $300 million. Also under the amendment, an incremental commitment in the amount of $75 million which could be borrowed in connection with the transactions discussed above was made available to the Company. The execution of the amendment by the lenders also constituted a waiver by the lenders permitting the transactions discussed above and provided for the EnCap

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Transaction. All of our subsidiaries are parties to the supplement and amendment documents and have pledged all or substantially all of their assets as collateral for the loans.

In connection with the transactions discussed above, on February 1, 2006, the Company issued and sold 13 million shares of its common stock for $14.50 per share, for an aggregate offering amount of approximately $188.5 million. The Company received approximately $180.8 million in net proceeds from the offering. The shares of common stock were privately placed in the offering and have not been registered under the Securities Act of 1933, as amended (the Act), or any state securities laws and, absent registration or an applicable exemption from such registration, may not be offered or sold in the United States. The common stock was offered and sold pursuant to the private placement exceptions from registration provided by Regulation D, Rule 506, under Section 4(2) of the Act and Regulation S of the Act. Shares of the common stock were offered and sold only to accredited investors (as defined in Rule 501(a) of the Act) and non-United States persons pursuant to the offers and sales that occur outside the United States within the meaning of Regulation S under the Act. The placement agents for this offering received a cash fee equal to approximately $7.7 million as compensation for services provided in connection with the offering and to reimburse the placement agents for certain expenses.

Pursuant to a related registration rights agreement by us and for the benefit of the purchasers in the aforementioned private offering, the Company agreed to file and cause to be declared effective by the SEC a registration statement covering resales of shares of the Company s common stock sold in this offering as promptly as reasonably practical and in any event within 75 days after the closing of the offering. If such registration statement is not filed and declared effective by the SEC on or prior to the date 75 days after the closing of the offering, then for each day following such date, but excluding the date the SEC declares the registration statement effective, the Company shall, for each said day, pay each holder of the Company s common stock purchased in that offering, as liquidating damages, an aggregate amount equal to $0.0048285 multiplied by the aggregate number of shares held by such holder.

On January 26, 2006, the Company entered into a stock purchase agreement with EnCap Investments, L.P. and certain of its affiliates (collectively EnCap), pursuant to which the Company agreed to repurchase, and EnCap agreed to sell, approximately 3.3 million shares of the Company s common stock held by EnCap at a price per share equal to the net proceeds per share that the Company received from the private offering. The stock purchase agreement was effective as of January 10, 2006.

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13. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	December 31, 2005	December 31, 2004
	(in thousands)	
Accounts receivable		
Oil and gas sales	$ 48,369	$ 20,603
Joint interest accounts	15,954	2,154
Other	3,764	394
	$ 68,087	$ 23,151
Accounts payable and accrued liabilities		
Trade payables	$ 16,379	$ 5,420
Revenues and royalties payable to others	22,273	6,026
Accrued capital costs	23,610	8,027
Accrued lease operating expenses	5,854	1,250
Other	21,901	3,953
	$ 90,017	$ 24,676

	Year Ended December 31, 2005	2004	2003
	(in thousands)		
Cash payments:			
Interest payments	$26,507	$2,766	$519
Income tax payments	24		33
Non-cash items excluded from the statement of cash flows:			
Accrued capital expenditures	$ 6,005	$1,915	$

On June 30, 2005, the Company entered into an agreement with PHAWK, LLC to convert its $35 million five-year unsecured subordinated convertible note into 8.75 million shares of Petrohawk common stock. See Note 3, *Long-term Debt* for more details.

In the fourth quarter of 2005, the Company entered into three natural gas put option contracts. These contracts contain deferred premiums of $4.1 million and will be paid as the contracts expire.

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14. SUPPLEMENTAL GUARANTOR INFORMATION

All subsidiaries of the Company (collectively the Guarantor Subsidiaries) are full and unconditional guarantors and are jointly and severally liable under the indenture of the 9 7/8% Notes. Condensed Consolidating Financial Statements for these Guarantor Subsidiaries are presented in the following tables:

CONDENSED CONSOLIDATING BALANCE SHEETS
As of December 31, 2005
(In thousands)

	Petrohawk	Guarantor Subsidiaries	Eliminations	Consolidated
Current assets	$ 51,771	$ 54,210	$	$ 105,981
Net oil and gas properties and other	68,457	1,072,493		1,140,950
Investment in subsidiaries	485,455		(485,455)	
Goodwill	132,029			132,029
Deferred taxes	2,367		(2,367)	
Other noncurrent assets	31,214			31,214
Total assets	$ 771,293	$ 1,126,703	$ (487,822)	$ 1,410,174
Current liabilities	$ 60,314	$ 83,572	$	$ 143,886
Long-term debt	495,801			495,801
Deferred taxes		155,522	(2,367)	153,155
Other noncurrent liabilities	62,005	28,869		90,874
Intercompany	(373,285)	373,285		
Stockholders equity	526,458	485,455	(485,455)	526,458
Total liabilities and stockholders equity	$ 771,293	$ 1,126,703	$ (487,822)	$ 1,410,174

CONDENSED CONSOLIDATING BALANCE SHEETS
As of December 31, 2004
(In thousands)

	Petrohawk	Guarantor Subsidiaries	Eliminations	Consolidated
Current assets	$ 14,896	$ 21,126	$	$ 36,022
Net oil and gas properties and other	50,803	435,361		486,164
Investment in subsidiaries	(7,308)		7,308	
Other	10,985	1,028		12,013
Total assets	$ 69,376	$ 457,515	$ 7,308	$ 534,199
Current liabilities	$ 8,222	$ 18,944	$	$ 27,166
Long-term debt	239,500			239,500
Other noncurrent liabilities	10,208	10,234		20,442
Intercompany	(435,645)	435,645		
Stockholders equity	247,091	(7,308)	7,308	247,091

Total liabilities and stockholders equity	$ 69,376	$ 457,515	$ 7,308	$ 534,199

CONDENSED CONSOLIDATING INCOME STATEMENTS
For the Year Ended December 31, 2005
(In thousands)

	Petrohawk	Guarantor Subsidiaries	Eliminations	Consolidated
Oil and gas sales	$ 65,052	$ 192,987	$	$ 258,039
Equity in earnings of subsidiaries, net of tax	47,496		(47,496)	
Operating expenses and other	164,125	119,611		283,736
Net income (loss) before income taxes	(51,577)	73,376	(47,496)	(25,697)
Income tax benefit (provision)	34,943	(25,880)		9,063
Net income (loss)	$ (16,634)	$ 47,496	$ (47,496)	$ (16,634)

CONDENSED CONSOLIDATING INCOME STATEMENTS
For the Year Ended December 31, 2004
(In thousands)

	Petrohawk	Guarantor Subsidiaries	Eliminations	Consolidated
Oil and gas sales	$ 7,077	$ 26,500	$	$ 33,577
Equity in earnings of subsidiaries, net of tax	1,679		(1,679)	
Operating expenses and other	(257)	24,588		24,331
Net income (loss) before income taxes	9,013	1,912	(1,679)	9,246
Income tax benefit (provision)	(896)	(233)		(1,129)
Net income (loss)	$ 8,117	$ 1,679	$ (1,679)	$ 8,117

CONDENSED CONSOLIDATING INCOME STATEMENTS
For the Year Ended December 31, 2003
(In thousands)

	Petrohawk	Guarantor Subsidiaries	Eliminations	Consolidated
Oil and gas sales	$ 4,100	$ 8,825	$	$ 12,925
Equity in earnings of subsidiaries, net of tax	659		(659)	
Operating expenses and other	3,785	8,150		11,935
Net income (loss) before income taxes and cumulative effect of accounting change	974	675	(659)	990
Income tax benefit (provision)	(8)	(16)		(24)
Net income (loss) before cumulative effect of accounting change	966	659	(659)	966
Cumulative effect of accounting change	2			2
Net income (loss)	$ 968	$ 659	$ (659)	$ 968

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CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2005
(In thousands)

	Petrohawk	Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities:				
Net loss	$ (16,634)	$ 47,496	$ (47,496)	(16,634)
Non-cash adjustments	200,594	(86,217)	47,496	161,873
Changes in assets and liabilities, net of acquisitions	(152,106)	142,313		(9,793)
Net cash provided by operating activities	31,854	103,592		135,446
Cash flows from investing activities:				
Net property, plant & equipment expenditures	453,523	(637,132)		(183,609)
Other	(22,500)			(22,500)
Net cash used in investing activities	431,023	(637,132)		(206,109)
Cash flows from financing activities:				
Borrowings, net of repayments	95,490			95,490
Proceeds from exercise of options	12,055			12,055
Other	(29,631)			(29,631)
Net cash provided by financing activities	77,914			77,914
Net increase in cash and cash equivalents	540,791	(533,540)		7,251
Cash and cash equivalents at beginning of period	(62,138)	67,798		5,660
Cash and cash equivalents at end of period	$ 478,653	$ (465,742)	$	$ 12,911

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
For the Year Ended December 31, 2004
(In thousands)

	Petrohawk	Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$ 8,117	$ 1,679	$ (1,679)	8,117
Non-cash adjustments	(9,806)	13,847	1,679	5,720
Changes in operating assets and liabilities, net of acquisitions	(463,829)	467,935		4,106
Net cash provided by operating activities	(465,518)	483,461		17,943

Cash flows from investing activities:			
Net property, plant & equipment expenditures	1,558	(401,623)	(400,065)
Other	(416)		(416)
Net cash used in investing activities	1,142	(401,623)	(400,481)
Cash flows from financing activities:			
Borrowings, net of repayments	399,595	(13,284)	386,311
Proceeds from issuance of common stock and warrants	25,629		25,629
Offering costs	(15,466)		