BHP BILLITON LTD
Form 6-K
March 01, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 6-K

REPORT OF FOREIGN PRIVATE ISSUER

PURSUANT TO RULE 13a-16 OR 15d-16

UNDER THE SECURITIES EXCHANGE ACT OF 1934

February 28, 2013

BHP BILLITON LIMITED

(ABN 49 004 028 077)

(Exact name of Registrant as specified in its charter)

BHP BILLITON PLC

(REG. NO. 3196209)

(Exact name of Registrant as specified in its charter)

VICTORIA, AUSTRALIA

(Jurisdiction of incorporation or organisation)

ENGLAND AND WALES

(Jurisdiction of incorporation or organisation)

180 LONSDALE STREET, MELBOURNE,	
VICTORIA	**NEATHOUSE PLACE, VICTORIA, LONDON,**
3000 AUSTRALIA	**UNITED KINGDOM**
(Address of principal executive offices)	**(Address of principal executive offices)**

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F: x Form 20-F ¨ Form 40-F

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): ¨

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ¨

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934: ¨ Yes x No

If Yes is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): n/a

An audited version of the accompanying Annual Report to Security Holders (the Petrohawk Annual Report) was provided to holders of Petrohawk Energy Corporation s (Petrohawk) outstanding senior notes in accordance with the reporting covenants under the applicable indentures. The condensed consolidated financial statements in the Report have been prepared in accordance with accounting principles generally accepted in the United States. Petrohawk s parent, BHP Billiton Limited, prepares its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS). Petrohawk utilizes the full cost method of accounting for its oil and natural gas activities compared to BHP Billiton Limited which utilizes the successful efforts method of accounting. In addition, the accompanying condensed consolidated financial statements are based on Petrohawk s historical accounting activities and do not reflect the acquisition of Petrohawk by BHP Billiton Limited or any of the fair value calculations that were performed in conjunction with the business combination accounting performed by BHP Billiton Limited. For the avoidance of doubt, the results of operations, financial position, cash flows and disclosures included in the Petrohawk Annual Report are not indicative of the contribution of Petrohawk to the potential results of BHP Billiton Limited.

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28 February 2013

To: Australian Securities Exchange[1]
London Stock Exchange

cc: New York Stock Exchange
JSE Limited

PETROHAWK 2012 ANNUAL REPORT

Petrohawk Energy Corporation (Petrohawk) provides periodic reports to holders of Petrohawk s senior notes as required in accordance with the reporting covenants under the applicable indentures. A copy of Petrohawk s 2012 Annual Report is attached, and will be provided to the holders of Petrohawk s outstanding senior notes today.

Petrohawk s financial statements are prepared in accordance with United States accounting standards whereas BHP Billiton Group financial statements are prepared in accordance with International Financial Reporting Standards and include the impact of the purchase price paid for Petrohawk. In addition, the consolidated financial statements contained in Annual Report are based on Petrohawk s historical accounting activities and do not reflect the acquisition of Petrohawk by BHP Billiton or any of the fair value calculations that were performed in conjunction with the business combination accounting performed by BHP Billiton. For the avoidance of doubt, the results of operations, financial position, cash flows and disclosures included in the Petrohawk 2012 Annual Report are not indicative of the contribution of Petrohawk to the potential results of BHP Billiton.

BHP Billiton purchased Petrohawk on 20 August 2011 and therefore only consolidates Petrohawk s results in its financial statements from that date.

Further information on BHP Billiton can be found at: www.bhpbilliton.com

Jane McAloon

Group Company Secretary

[1] This release was made outside the hours of operation of the ASX market announcements office.

PETROHAWK ENERGY CORPORATION

ANNUAL REPORT TO SECURITY HOLDERS

DECEMBER 31, 2012

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The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States. Petrohawk Energy Corporation s (Petrohawk or the Company) parent, BHP Billiton Limited, prepares its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS). The Company utilizes the full cost method of accounting for its oil and natural gas activities compared to BHP Billiton Limited which utilizes the successful efforts method of accounting. In addition, the accompanying consolidated financial statements are based on the Company s historical accounting activities and do not reflect the acquisition of the Company by BHP Billiton Limited or any of the fair value allocations that were performed in conjunction with the business combination accounting performed by BHP Billiton Limited. Although the Company is wholly owned by BHP Billiton Limited, the Company has not established a new basis of accounting as such push down accounting from BHP Billiton Limited was deemed inappropriate for the accompanying consolidated financial statements due to the nature of Petrohawk s agreement with the bondholders. For the avoidance of doubt, the results of operations, financial position, cash flows and disclosures included in this document are not indicative of the potential contribution to the results of BHP Billiton Limited. Additionally, the Supplemental Oil and Gas Information is presented for purposes of additional analysis and is not a required part of the basic financial statements.

Notice of Change in Fiscal Year

On February 19, 2013, the Directors adopted a resolution authorizing a change in the Company s fiscal year from a calendar year to a July 1 through June 30 fiscal year, to align with BHP Billiton Limited s fiscal year. The Company s transitional financial report to Security Holders will cover the period from January 1, 2013 through June 30, 2013, and will include all information otherwise required in an annual report to bondholders under section 4.2 of the Indentures.

Special note regarding forward-looking statements

This Annual Report contains, and we may from time to time otherwise make in other public filings, forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number and location of wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as may, expect, estimate, project, plan, believe, intend, achievable, anticipate, will, continue, potential, should, could and sim
Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:

- our ability to successfully integrate our business with affiliates of BHP Billiton Limited;
- our ability to retain key members of senior management and key technical employees;
- volatility in commodity prices for oil and natural gas;
- the possibility that the industry may be subject to future regulatory or legislative actions (including any changes in tax law and changes in environmental regulation);
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the potential for production decline rates for our wells to be greater than we expect;
- our ability to replace oil and natural gas reserves;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- competition, including competition for acreage in resource play areas;
- management s ability to execute our plans to meet our goals;
- the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars;

access to and availability of water and other treatment materials to carry out planned fracture stimulations in our resource plays;

access to adequate gathering systems and transportation take-away capacity, necessary to fully execute our capital program;

our ability to secure firm transportation and other marketing outlets for the natural gas, natural gas liquids and crude oil and condensate we produce and to sell these products at market prices;

general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas;

social unrest, political instability, armed conflict, or acts of terrorism or sabotage in oil and natural gas producing regions, such as the Middle East, or our markets; and

other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or pricing.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. We do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

MANAGEMENT S NARRATIVE ANALYSIS OF RESULTS OF OPERATIONS

The following discussion is intended to assist in understanding our results of operations and our current financial condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report 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 above, which could cause actual results to differ from those expressed.

Overview

We are an oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located in the United States. On August 25, 2011, BHP Billiton Limited, a corporation organized under the laws of Victoria, Australia (BHP Billiton Limited), acquired 100% of our outstanding shares of common stock through the merger of a wholly owned subsidiary of BHP Billiton Petroleum (North America) Inc., a Delaware corporation and wholly owned subsidiary of BHP Billiton Limited, with and into Petrohawk, with Petrohawk continuing as the surviving entity. At the date of this report, Petrohawk remains an indirect, wholly owned subsidiary of BHP Billiton Limited (our Parent).

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

Our cash flows are subject to a number of variables including our level of oil and natural gas production and commodity prices, as well as various economic conditions that have historically affected the oil and natural gas industry. If natural gas prices remain at their current levels for a prolonged period of time or if oil and natural gas prices decline, our ability to fund our capital expenditures, reduce debt, meet our financial obligations and become profitable may be materially impacted. Our primary sources of capital and liquidity, prior to the acquisition by BHP Billiton Limited, have been internally generated cash flows from operations, proceeds from asset sales and availability under our Senior Credit Agreement. As of the date of acquisition by BHP Billiton Limited, our capital resources and liquidity have been and will continue to be from internally generated cash flows from operations and funding from our Parent or otherwise arranged with third party lenders in accordance with the indentures governing our four outstanding series of senior notes.

Contractual Obligations

We believe we have a significant degree of flexibility to adjust the level of our future capital 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 natural 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 as of December 31, 2012.

		Payments Due By Period			
Contractual Obligations	**Total**	**2013**	**2014 2015 (In thousands)**	**2016 2017**	**2018 and Beyond**
6.25% $600 million senior notes[(1)]	$ 600,000	$	$	$	$ 600,000
7.25% $1.2 billion senior notes[(2)]	1,225,000				1,225,000
10.5% $600 million senior notes[(3)]	589,640		589,640		
7.875% $800 million senior notes[(4)]	799,611		799,611		
Interest expense on long-term debt[(5)]	996,061	250,474	376,928	252,625	116,034
Total debt	4,210,312	250,474	1,766,179	252,625	1,941,034
Gathering and transportation contracts	3,324,057	425,143	886,910	647,191	1,364,813
Rig commitments	904,129	265,194	459,370	173,889	5,676
Pipeline and well equipment	232,364	232,364			
Other commitments[(6)]	57,095	57,095			
Operating leases	22,630	7,355	11,339	3,280	656
Total commitments	4,540,275	987,151	1,357,619	824,360	1,371,145
Total contractual obligations	**$ 8,750,587**	**$ 1,237,625**	**$ 3,123,798**	**$ 1,076,985**	**$ 3,312,179**

(1) On May 20, 2011, we issued $600 million principal amount of our 6.25% senior notes due 2019. See 6.25% Senior Notes in *Consolidated Financial Statements and Supplementary Data* Note 4, *Long-Term Debt* for further details.

(2) On August 17, 2010, and January 31, 2011, we issued an initial $825 million principal amount and an additional $400 million principal amount, respectively, of our 7.25% senior notes due 2018. The amount excludes a $5.9 million unamortized premium at December 31, 2012, which was recorded in conjunction with the issuance of the additional 2018 Notes. See 7.25% Senior Notes in *Consolidated Financial Statements and Supplementary Data* Note 4, *Long-Term Debt* for further details.

(3) Excludes $18.4 million unamortized discount recorded in conjunction with the issuance of the notes. See 10.5% Senior Notes in *Consolidated Financial Statements and Supplementary Data* Note 4, *Long-Term Debt* for further details.

(4) See 7.875% Senior Notes in *Consolidated Financial Statements and Supplementary Data* Note 4, *Long-Term Debt* for further details.

(5) Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2012, less required annual repayments.

(6) Other commitments pertains to exploration, development and production activities including, among other things, commitments for obtaining and processing seismic data.

For more information on amounts not included in the table above, refer *Consolidated Financial Statements and Supplementary Data* Note 7*, Commitments and Contingencies.*

Off-Balance Sheet Arrangements

At December 31, 2012, we did not have any material off-balance sheet arrangements.

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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. 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 natural 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. We also describe the most significant estimates and assumptions we make in applying these policies. We discuss the development, selection and disclosure of each of these with our Financial Reporting Committee. See Results of Operations and *Consolidated Financial Statements and Supplementary Data* Note 1, *Summary of Significant Events and Accounting Policies,* for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical 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 natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using the unweighted arithmetic average of the first day of the month for each of the 12-month prices for oil and natural gas within the period, holding prices and costs constant and applying a 10% discount rate.

Full Cost Method

We use the full cost method of accounting for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural 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. All general and administrative costs unrelated to drilling activities are expensed as incurred. The capitalized costs of our oil and natural 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 could have been significantly different had we used the successful efforts method of accounting for our oil and natural gas activities.

Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and SEC guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling test limitation. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under defined 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 accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions and (iv) the judgment of the persons preparing the estimate. 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 natural 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 year ended December 31, 2012, were prepared internally, and our estimated proved reserves for the years ended December 31, 2011 and 2010, were prepared by an independent third party oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Consolidated Financial Statements and Supplementary Data *Supplemental Oil and Gas Information* , as well as our Forms 10-K for the years ended December 31, 2011 and 2010.

Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. A five percent positive or negative revision to proved reserves would decrease or increase the DD&A rate by approximately $0.12 per Mcfe.

Full Cost Ceiling Test Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural 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 natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write downs of our oil and natural gas properties could occur in the future.

If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2012, had been 10% lower while all other factors remained constant, the net book value of oil and natural gas properties would still not exceed the ceiling amount, as the value would remain under the ceiling by approximately $1.4 billion before income taxes and $0.9 billion after income taxes.

Our parent, BHP Billiton Limited, prepares its consolidated financial statements in accordance with International Financial Reporting Standards (IFRS). For a discussion of BHP Billiton s accounting policies, please see the BHP Billiton 2012 Annual Report. For the avoidance of doubt, the ceiling test results listed above are not indicative of the potential results of any future BHP Billiton Limited impairment review under IFRS.

Future Development 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 facilities, gathering systems and related structures and restoration costs. 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. A five percent decrease or increase in future development and abandonment costs would decrease or increase the DD&A rate by approximately $0.06 per Mcfe.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities associated with our oil and natural gas wells and our gathering systems, and to restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are associated with plugging and abandoning wells and our gathering systems. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments.

Accounting for Derivative Instruments and Hedging Activities

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging*, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. From time to time, we have hedged a portion of our forecasted oil, natural gas and natural gas liquids production. Derivative contracts entered into by us have consisted of transactions in which we hedged the variability of cash flow related to a forecasted transaction. We elected to not designate any of our positions for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *Net gain on derivative contracts* on the consolidated statements of operations.

As detailed further in *Consolidated Financial Statements and Supplementary Data* Note 8, *Derivatives,* outstanding derivative positions have been terminated such that at December 31, 2012, the Company had no open commodity derivative contracts.

Goodwill

We account for goodwill in accordance with ASC 350, *Intangibles Goodwill and Other* (ASC 350). 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 an acquisition. ASC 350 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 that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units.

In September 2011, the Financial Accounting Standards Board issued ASU No. 2011-08, *Testing Goodwill for Impairment* (ASU 2011-08) to simplify how companies test goodwill for impairment. ASU 2011-08 simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying amount. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then the entity does not have to perform the two-step impairment test. However, if that same conclusion is not reached, the company is required to perform the first step of the two-step impairment test. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test. The first step is to compare the fair value of a reporting unit with its carrying value, including goodwill. If the fair value of a reporting unit is less than its carrying value, then the second step of the test must be performed to measure the amount of the impairment loss, if any.

We perform our goodwill test annually during the third quarter or more often if circumstances require. During the third quarter of 2012, we elected to first assess qualitative factors. Our qualitative assessment included an evaluation of factors such as macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, as well as other relevant events and circumstances that affect the fair value or carrying amount. Based on this qualitative assessment, there was no impairment indicators that would indicate that it is more likely than not that the fair value of the Company s oil and gas reporting unit is less than its carrying amount. As such, we did not perform the two-step goodwill impairment test during 2012. In previous years, our goodwill impairment reviews consisted of the two-step process. The first step is to determine the fair value of our reporting unit and compare it to the carrying value of the related net assets. Fair value is determined based on our estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write-down is required. The second step is required if the fair value of the reporting unit is less than the book value of the net assets. In this step, the implied fair value of the reporting unit is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written-down to its implied fair value. If the fair value of the reporting unit 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 against earnings. The assumptions we used in calculating our reporting unit fair values at the time of the test in prior years include our market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas prices. Material adverse changes to any of the factors considered could lead to an impairment of all or a portion of our goodwill in future periods.

Income Taxes

Our provision for taxes includes both state and federal taxes. We account 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.

We follow ASC 740, *Income Taxes*, (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the financial statements. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows. The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement. Effective with the BHP Merger, Petrohawk is part of the BHP Billiton Limited s United States Federal consolidated tax group and does not file stand-alone income tax returns for federal tax purposes.

Accounting for KinderHawk and EagleHawk Joint Venture

KinderHawk and the EagleHawk joint venture are accounted for as failed sales of in substance real estate under the provisions of ASC 360-20, *Property, Plant and Equipment Real Estate Sales* (ASC 360-20). ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller s business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Haynesville Shale and Eagle Ford Shale gathering and treating systems consist of right of ways, pipelines and processing facilities. Due to the gathering agreements, entered into with the formation of KinderHawk and EagleHawk, which constitute extended continuing involvement under ASC 360-20, it has been determined that the contribution of our Haynesville Shale gathering and treating system to KinderHawk and our contribution of our Eagle Ford Shale gathering and treating system to EagleHawk should be accounted for as failed sales of in substance real estate. As a result of the failed sales, we account for the continued operations of the gas gathering systems and reflect financing obligations, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Haynesville Shale and Eagle Ford Shale gas gathering systems contributed to KinderHawk and EagleHawk, respectively, are carried at the full historical basis of the assets on the consolidated balance sheets in *Gas gathering systems and equipment* and depreciated over the remaining useful life of the assets. The financing obligations of $1.9 billion as of December 31, 2012, are recorded on the consolidated balance sheets in *Payable on financing arrangements.* Reductions to the obligations and the non-cash interest on the obligations are tied to the gathering and treating services, as we deliver natural gas through the Haynesville Shale and Eagle Ford Shale gathering and treating systems. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon our weighted average cost of debt as of the date of the transactions. Allocable income in excess of the calculated value will be reflected as reductions of principal. Interest is recorded in *Interest expense and other* on the consolidated statements of operations. Additionally we record EagleHawk s revenues, and through July 1, 2011, we recorded KinderHawk s revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to us, and expenses on the consolidated statements of operations in *Midstream revenues,* *Taxes other than income,* *Gathering, transportation and other,* *General and administrative,* *Interest expense and other* and *Depletion, depreciation and amortization.*

On July 1, 2011, we closed a transaction with KM Gathering in which we transferred our remaining 50% membership interest in KinderHawk to KM Gathering. Upon the closing of the transfer of our remaining 50% interest in KinderHawk, we no longer include KinderHawk s revenues and expenses on the consolidated statements of operations. In accordance with ASC 360-20, the historical cost of the Haynesville Shale gas gathering system is carried at the full historical basis of the assets on the consolidated balance sheets in *Gas gathering systems and equipment* and depreciated over the remaining useful life of the assets, as discussed above. As a result of the transfer on July 1, 2011, we recorded an increase in our financing obligation associated with KinderHawk of approximately $743.0 million.

Comparison of Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

We reported a loss from continuing operations, net of income taxes, of $174.4 million for the year ended December 31, 2012, compared to income from continuing operations, net of income taxes, of $177.2 million for the comparable period in 2011. The following table summarizes key items of comparison and their related change for the periods indicated.

	Years Ended December 31,		
(In thousands (except per unit and per Mcfe amounts))	**2012**	**2011**	**Change**
Income (loss) from continuing operations, net of	$ (174,432)	$ 177,227	$ (351,659)
Operating revenues:			
Oil and natural gas	2,023,561	1,779,738	243,823
Marketing	7,384	296,006	(288,622)
Midstream	75,897	23,648	52,249
Operating expenses:			
Marketing	6,884	322,232	(315,348)
Production:			
Lease operating	88,848	62,295	26,553
Workover and other	14,283	17,853	(3,570)
Taxes other than income	75,293	63,617	11,676
Gathering, transportation and other	316,200	175,494	140,706
General and administrative:			
General and administrative	180,079	228,964	(48,885)
Stock-based compensation		53,203	(53,203)
Depletion, depreciation and amortization:			
Depletion Full cost	1,106,449	823,841	282,608
Depreciation Midstream	33,300	22,888	10,412
Depreciation Other	31,080	10,869	20,211
Accretion expense	2,626	2,126	500
Impairment of intangible asset	67,237		67,237
Impairment of capitalized software costs	1,351		1,351
Other income (expenses):			
Net gain on derivative contracts	(28,260)	363,714	(391,974)
Interest expense and other	(433,046)	(403,952)	(29,094)
Income from continuing operations before income	(278,094)	275,772	(553,866)
Income tax benefit (provision)	103,662	(98,545)	202,207
Production:			
Natural gas Mmcf	344,305	311,178	33,127
Crude oil MBbl	9,350	4,715	4,635
Natural gas liquids MBbl	5,989	2,843	3,146
Natural gas equivalent Mmcfe[(1)]	436,339	356,526	79,813
Average daily production Mmcfe[(1)]	1,195	977	218
Average price per unit[(2)]:			
Natural gas price Mcf	$ 2.59	$ 3.87	(1.28)
Crude oil price Bbl	97.43	89.75	7.68
Natural gas liquids price Bbl	33.93	49.89	(15.96)
Natural gas equivalent price Mcfe[(1)]	4.59	4.96	(0.37)
Average cost per Mcfe:			
Production:			
Lease operating	0.20	0.17	0.03
Workover and other	0.03	0.05	(0.02)
Taxes other than income	0.17	0.18	(0.01)
Gathering, transportation and other	0.72	0.49	0.23
General and administrative:			
General and administrative	0.41	0.64	(0.23)

Stock-based compensation		0.15	(0.15)
Depletion	2.54	2.31	0.23

(1) Oil and natural gas liquids are converted to equivalent gas production using a 6:1 equivalent ratio. This ratio does not assume price equivalency and given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

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

For the year ended December 31, 2012, oil and natural gas revenues increased $243.8 million from the same period in 2011, to $2.0 billion. The increase was primarily due to the increase in our production of 79,813 Mmcfe, or 22% over 2011, primarily due to our drilling successes in resource plays in Louisiana and Texas. Increased production contributed approximately $396 million in revenues for the year ended December 31, 2012. The increase related to production was partially offset by a decrease of $0.37 per Mcfe in our realized average price to $4.59 per Mcfe from $4.96 per Mcfe in the prior year period. The decrease per Mcfe led to a decrease in oil and natural gas revenues of approximately $161 million.

We had marketing revenues of $7.4 million and marketing expenses of $6.9 million for the year ended December 31, 2012, resulting in income before income taxes of $0.5 million as compared to a loss before income taxes of $26.2 million for the same period in 2011. Prior to July 1, 2011, a subsidiary of ours purchased and sold our own and third party natural gas produced from wells which we and third parties operate. Effective July 1, 2011, our marketing subsidiary ceased its marketing operations. The revenues and expenses related to these marketing activities were reported on a gross basis as part of operating revenues and operating expenses in historical periods. Marketing revenues were recorded at the time natural gas was physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases were recorded as our subsidiary took physical title to natural gas and transported the purchased volumes to the point of sale. Subsequent to July 1, 2011, we substantially decreased activity related to buying and selling third party volumes from wells we and third parties operate. As a result, certain items previously recorded to *Marketing revenues* are no longer reported while others are now recorded to *Oil and natural gas revenues* on the consolidated statements of operations. In addition, certain charges previously reported in *Marketing expenses* are no longer reported while others are now recorded to *Gathering, transportation and other* on the consolidated statements of operations.

We had gross revenues from our midstream business of $132.8 million for the year ended December 31, 2012, compared to the same period in 2011 of $87.3 million, an increase of $45.5 million. The increase in gross revenues from our midstream business primarily relates to increased volumes from our gathering and treating system in the Eagle Ford Shale. In accordance with the financing method for a failed sale of in substance real estate we record EagleHawk s revenues, and through July 1, 2011, we recorded KinderHawk s revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to us on the consolidated statements of operations. For the year ended December 31, 2012, approximately $54.1 million in revenues, after intercompany eliminations, from EagleHawk were reported in midstream revenues on the consolidated statements of operations. Gross revenues of $132.8 million also included $56.9 million of intercompany revenues that were eliminated in consolidation. On a net basis, we had revenues of $75.9 million for the year ended December 31, 2012, an increase of $52.2 million from the prior year. This increase is attributed to increased volumes from our gathering and treating system in the Eagle Ford Shale.

Lease operating expenses increased $26.6 million for the year ended December 31, 2012, as compared to the same period in 2011. The increase was primarily due to an increase in the number of wells, combined with increased production. On a per unit basis, lease operating expenses increased $0.03 per Mcfe to $0.20 per Mcfe in 2012 from $0.17 per Mcfe in 2011, primarily due to slightly higher costs per Mcfe on base wells in dry gas areas.

Taxes other than income increased $11.7 million for year ended December 31, 2012, as compared to the same period in 2011. The largest components of taxes other than income are production and severance taxes which are generally assessed as either a fixed rate based on production or as a percentage of gross oil and natural gas sales. Our increase in production in the current year was partially offset by severance tax refunds related to drilling incentives for horizontal wells in the Haynesville and Eagle Ford Shales. For the year ended December 31, 2012, we recorded severance tax refunds totaling $21.4 million compared to $16.6 million in the prior year. On a per unit basis, excluding the severance tax refunds, taxes other than income were $0.22 per Mcfe in 2012 compared to $0.23 per Mcfe in 2011.

Gathering, transportation and other expense increased $140.7 million for the year ended December 31, 2012 as compared to the same period in 2011. On a per unit basis, gathering transportation and other increased $0.23 per Mcfe from $0.49 per Mcfe in 2011 to $0.72 per Mcfe in 2012. The overall increase is due to higher cost per unit for liquids and an increase in volumes, combined with deficiency payments associated with unutilized firm transportation capacity.

General and administrative expense for the year ended December 31, 2012, decreased $48.9 million as compared to the same period in 2011. The decrease is primarily attributable to costs associated with the BHP Merger in 2011 which were not incurred during 2012, as well as a decrease in normal payroll and employee costs which is primarily associated with decreases in bonuses as a result of increased employee departures. An advisory service fee paid in conjunction with the BHP Merger in 2011 accounted for $30.2 million of the decrease for the current period. Payroll and employee costs decreased approximately $8.8 million for items including employee retention and bonus payments and associated payroll taxes, partially offset by normal increases in payroll and employee costs due to our growth over the prior year. We also incurred professional and legal fees of approximately $8.5 million related to the BHP Merger during 2011.

Stock-based compensation expense for the year ended December 31, 2012, decreased $53.2 million to nothing compared to the same period in 2011. On August 25, 2011, BHP Billiton Limited acquired 100% of our outstanding shares of common stock through the merger of a wholly owned subsidiary of BHP Billiton Petroleum (North America) Inc. with and into us. In conjunction with the merger, we cancelled all unexercised stock options and stock appreciation rights, both vested and unvested, outstanding under our employee and nonemployee equity incentive plans in exchange for a cash payment equal to $38.75 for each share of common stock underlying such option or stock appreciation right, less the applicable exercise price per share and net of withholding taxes, which resulted in our recognition of additional stock-based compensation expense in 2011.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense increased $282.6 million for the year ended December 31, 2012, from the same period in 2011, to $1.1 billion. On a per unit basis, depletion expense increased $0.23 per Mcfe to $2.54 per Mcfe. The increase on a per unit basis is primarily due to the impact of our 2011 and 2012 capital expenditures program.

Depreciation expense associated with our gas gathering systems increased $10.4 million to $33.3 million for the year ended December 31, 2012, as compared to the same period in 2011. The increase was due to the growth in our midstream operations from capital spending over the course of the year. We depreciate our gas gathering systems over a 30 year useful life commencing on the estimated placed in service date.

Depreciation expense associated with our other operating property and equipment increased $20.2 million to $31.1 million for the year ended December 31, 2012, as compared to the same period in 2011. The increase is primarily due to expansion and the growth of our capital spending during 2012.

During 2012, one acquired transportation contract (the Kaiser contract) for gas export from Haynesville field reached a point at which we had the option to cancel or extend the contract at our sole discretion. Due to changes in the gas market since the time of acquisition and the availability of alternative transportation routes, the decision was made not to extend this contract. As a result, a change in circumstances was noted and the remaining net book value of approximately $67.2 million associated with the Kaiser contract was impaired and recorded to *Impairment of intangible asset* in the consolidated statements of operations.

During the first quarter of 2012, we made the decision to cease implementation of a new budgeting software program. As such, we impaired the capitalized costs associated with this software implementation in the first quarter of 2012. Approximately $1.3 million was recorded to *Impairment of capitalized software costs* in the consolidated statements of operations.

Historically, we have entered into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil, natural gas and natural gas liquids production. We did not elect to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statements of operations. On December 20, 2011, we entered into a Master Transaction Agreement (the MTA) with Barclays Bank PLC (Barclays) in order to facilitate the termination of a portion of our existing derivative positions. As part of the MTA, we entered into certain derivative transactions with Barclays with equal and opposite economic terms from the majority of our existing derivative positions (Mirror Trades). During the first quarter of 2012, we novated the existing derivative positions to Barclays and terminated the existing derivative positions as well as the Mirror Trades and Barclays paid us approximately $209 million. In addition, during the first quarter of 2012, we received $68.5 million for the termination of our outstanding derivative positions with BNP Paribas. During the year ended December 31, 2012, we recorded a net derivative loss of $28.3 million ($336.1 million net unrealized loss and a $307.8 million net gain for cash received on settled contracts). During the year ended December 31, 2011, we recorded a net derivative gain of $363.7 million ($90.1 million net unrealized gain and $273.6 million net gain for cash received on settled contracts).

Interest expense and other increased $29.1 million for the year ended December 31, 2012, compared to the same period in 2011. The increase is primarily the result of our accounting for KinderHawk and the EagleHawk joint venture under the financing method for a failed sale of in substance real estate. For the year ended December 31, 2012, we recorded approximately $163.5 million of interest expense on the financing obligations compared to $116.4 million in the prior year.

We had an income tax benefit of $103.7 million for the year ended December 31, 2012, due to our loss from continuing operations before income taxes of $278.1 million compared to an income tax provision of $98.5 million due to our income from continuing operations before income taxes of $275.8 million in the prior year. The effective tax rate for the year ended December 31, 2012, was 37.3% compared to 35.7% for the year ended December 31, 2011. The increase in our effective tax rate in the current year is primarily due to non-recurrence of the prior year impact of the acceleration of certain equity awards as a result of the BHP Merger.

Investment in EagleHawk

EagleHawk had gross revenues of $94.0 million related to its Eagle Ford Shale gathering and treating systems in the Hawkville and Black Hawk Fields for the year ended December 31, 2012, compared to $26.1 million from July 1, 2011, the date of inception, to December 31, 2011. Gross revenues include $39.9 million and $14.1 million of intercompany revenues that were eliminated in consolidation for the years ended December 31, 2012 and 2011, respectively. Total operating expenses for EagleHawk for the year ended December 31, 2012, of $47.0 million included $23.5 million in gathering, transportation and other expenses and $17.5 million in depreciation expense. Gross revenues for the six months ended December 31, 2011, of $13.9 million included $7.7 million in gathering, transportation and other expenses and $4.7 million in depreciation expense. Gathering, transportation and other expenses for EagleHawk consist of costs to operate the pipelines, such as treating, processing, measuring and transporting expenses. Depreciation expense on EagleHawk s gathering and treating systems is calculated based on a 30 year useful life commencing on the estimated placed in service date.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in *Consolidated Financial Statements and Supplementary Data* Note 1, *Summary of Significant Events and Accounting Policies*.

CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands)

	Years Ended December 31,		
	2012	**2011**	**2010**
Operating revenues:			
Oil and natural gas	$ 2,023,561	$ 1,779,738	$ 1,107,401
Marketing	7,384	296,006	475,030
Midstream	75,897	23,648	18,216
Total operating revenues	2,106,842	2,099,392	1,600,647
Operating expenses:			
Marketing	6,884	322,232	521,378
Production:			
Lease operating	88,848	62,295	64,744
Workover and other	14,283	17,853	18,119
Taxes other than income	75,293	63,617	9,543
Gathering, transportation and other	316,200	175,494	99,375
General and administrative	180,079	282,167	155,493
Depletion, depreciation and amortization:	1,173,455	859,724	465,970
Impairment of intangible asset	67,237		
Impairment of capitalized software costs	1,351		
Total operating expenses	1,923,630	1,783,382	1,334,622
Income (loss) from operations	183,212	316,010	266,025
Other income (expenses):			
Net gain (loss) on derivative contracts	(28,260)	363,714	301,121
Interest expense and other	(433,046)	(403,952)	(336,307)
Total other income (expenses)	(461,306)	(40,238)	(35,186)
Income (loss) from continuing operations before income taxes	(278,094)	275,772	230,839
Income tax benefit (provision)	103,662	(98,545)	(94,934)
Income (loss) from continuing operations, net of income taxes	(174,432)	177,227	135,905
Loss from discontinued operations, net of income taxes		(3,079)	(45,984)
Net income (loss)	$ (174,432)	$ 174,148	$ 89,921

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

PETROHAWK ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

	December 31, 2012	December 31, 2011
Current assets:		
Cash	$ 96,122	$ 174,436
Accounts receivable	584,442	410,115
Receivables from derivative contracts		371,584
Deferred income tax	16,046	
Prepaid and other	29,798	42,060
Total current assets	726,408	998,195
Oil and natural gas properties (full cost method):		
Evaluated	13,213,484	10,509,954
Unevaluated	2,839,950	2,502,435
Gross oil and natural gas properties	16,053,434	13,012,389
Less accumulated depletion	(6,708,875)	(5,598,420)
Net oil and natural gas properties	9,344,559	7,413,969
Other operating property and equipment:		
Gas gathering systems and equipment	1,348,822	918,810
Other operating assets	130,026	108,077
Gross other operating property and equipment	1,478,848	1,026,887
Less accumulated depreciation	(126,366)	(61,363)
Net other operating property and equipment	1,352,482	965,524
Other noncurrent assets:		
Goodwill	932,802	932,802
Other intangible assets, net of amortization		78,289
Debt issuance costs, net of amortization	36,090	45,528
Deferred income taxes	352,446	326,878
Receivables from derivative contracts		5,147
Restricted cash	27,647	34,736
Other	14,792	11,859
Total assets	$ 12,787,226	$ 10,812,927
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,166,106	$ 963,701
Deferred income taxes		79,748
Liabilities from derivative contracts		40,673
Payable to financing arrangements	19,467	17,631
Current portion of long-term debt		17,520
Total current liabilities	1,185,573	1,119,273

Long-term debt	3,201,761	3,192,641
Other noncurrent liabilities:		
Asset retirement obligations	57,236	52,317
Payable on financing arrangements	1,853,343	1,799,881
Other	417	640
Commitments and contingencies (Note 7)		
Stockholders equity:		
Common stock: 100 shares of $.001 par value authorized, issued and outstanding at December 31, 2012 and 2011		
Additional paid-in capital	7,675,552	5,660,399
Accumulated deficit	(1,186,656)	(1,012,224)
Total stockholders equity	6,488,896	4,648,175
Total liabilities and stockholders equity	$ 12,787,226	$ 10,812,927

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

PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In thousands)

	Common		**Additional**		**Total**
	Shares	**Amount**	**Paid-in Capital**	**Accumulated Deficit**	**Stockholders Equity**
Balances at January 1, 2010	301,195	$ 301	$ 4,599,664	$ (1,276,293)	$ 3,323,672
Equity compensation vesting			32,637		32,637
Common stock issuances	1,495	1	3,076		3,077
Purchase of shares to cover individuals tax withholding	(171)		(3,672)		(3,672)
Reduction in shares to cover individuals tax withholding	(29)		(96)		(96)
Net income				89,921	89,921
Balances at December 31, 2010	302,490	302	4,631,609	(1,186,372)	3,445,539
Equity compensation vesting			76,662		76,662
Common stock issuances	1,661	2	5,477		5,479
Common stock cancelled	(303,898)	(304)	304		
Restricted stock awards settled			(85,904)		(85,904)
Stock option awards and stock option appreciation rights settled			(224,216)		(224,216)
Common stock issuances to parent[1]					
Contribution from parent			1,260,891		1,260,891
Purchase of shares to cover individuals tax withholding	(195)		(4,090)		(4,090)
Reduction in shares to cover individuals tax withholding	(58)		(334)		(334)
Net income				174,148	174,148
Balance at December 31, 2011			5,660,399	(1,012,224)	4,648,175
Contribution from parent[2]			2,015,153		2,015,153
Net income				(174,432)	(174,432)
Balance at December 31, 2012			**$ 7,675,552**	**$ (1,186,656)**	**$ 6,488,896**

(1) Includes 100 shares of common stock issued and outstanding to BHP Billiton Petroleum (North America) Inc., a wholly owned subsidiary of BHP Billiton Limited at a par value of $0.001 per share. Shares were issued during the third quarter of 2011.

(2) Includes both cash funding and non-cash contributions from BHP Billiton Limited. The cash funding for 2012 totals approximately $2.0 billion, and the remainder is attributable to non-cash contributions, which are items paid by BHP Billiton Limited on behalf of Petrohawk.

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

PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2012	2011	2010
Cash flows from operating activities:			
Net income (loss)	$ (174,432)	$ 174,148	$ 89,921
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	1,173,455	858,377	470,172
Impairment of capitalized software costs	1,351		
Income tax provision (benefit)	(103,662)	96,690	66,686
Impairment of assets and loss on sale	67,237	3,950	70,195
Stock-based compensation		53,203	23,229
Net unrealized (gain) loss on derivative contracts	318,538	(90,127)	(58,075)
Loss on early extinguishment of debt			38,404
Other operating	46,196	53,781	45,381
Change in assets and liabilities:			
Accounts receivable	(174,327)	(121,933)	(183,708)
Payable to KinderHawk Field Services LLC		(976)	976
Prepaid and other	13,102	25,643	(30,523)
Accounts payable and accrued liabilities	100,221	26,388	(41,424)
Other	191	(4,622)	14,393
Net cash provided by operating activities	1,267,870	1,074,522	505,627
Cash flows from investing activities:			
Oil and natural gas capital expenditures	(2,946,239)	(2,950,164)	(2,424,292)
Proceeds received from sale of oil and natural gas properties		86,438	1,178,937
Proceeds received from sale of Fayetteville gas gathering systems		76,898	
Acquisition of CEU Hawkville LLC, net of cash acquired of $0		(92,974)	
Marketable securities purchased		(896,006)	(1,122,016)
Marketable securities redeemed		896,006	1,122,016
Increase in restricted cash	(380,088)	(348,971)	(198,210)
Decrease in restricted cash	387,177	314,235	411,914
Other operating property and equipment capital expenditures	(439,762)	(346,712)	(282,352)
Net cash used in investing activities	(3,378,912)	(3,261,250)	(1,314,003)
Cash flows from financing activities:			
Proceeds from exercise of stock options and warrants		5,426	2,927
Contribution from parent	1,993,999	1,258,375	
Restricted stock awards settled		(85,904)	
Stock option awards and stock option appreciation rights settled		(224,216)	
Proceeds from borrowings		4,413,500	3,362,000
Repayment of borrowings		(3,849,797)	(3,449,402)
Increase in payable on financing arrangements	72,279	886,119	917,437
Decrease in payable on financing arrangements	(33,550)	(13,532)	
Debt issuance costs		(25,983)	(20,738)
Other		(4,415)	(3,768)
Net cash provided by financing activities	2,032,728	2,359,573	808,456

Net increase (decrease) in cash	(78,314)	172,845	80
Cash at beginning of period	174,436	1,591	1,511
Cash at end of period	$ 96,122	$ 174,436	$ 1,591

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

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 engaged in the exploration, development and production of predominately natural gas properties located in the United States. As further discussed under the heading *Merger* below, on August 25, 2011, BHP Billiton Limited, a corporation organized under the laws of Victoria, Australia (BHP Billiton Limited), acquired 100% of the outstanding shares of Petrohawk through the merger of a wholly owned subsidiary of BHP Billiton Petroleum (North America) Inc., a Delaware corporation (which is a wholly owned subsidiary of BHP Billiton Limited), with and into Petrohawk, with Petrohawk continuing as the surviving entity. Petrohawk remains an indirect, wholly owned subsidiary of BHP Billiton Limited. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries of the Company. All intercompany accounts and transactions between Petrohawk and its controlled subsidiaries have been eliminated. These consolidated financial statements reflect, in the opinion of the Company s management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and the results of operations for, the periods presented.

Subsequent events or transactions have been evaluated through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements, and the Company has included those subsequent events within the following notes where applicable.

Merger

On July 14, 2011, the Company entered into an agreement and plan of merger (Merger Agreement) with BHP Billiton Limited (Guarantor), BHP Billiton Petroleum (North America) Inc. (Parent), a Delaware corporation and a wholly owned subsidiary of Guarantor, and North America Holdings II Inc., a Delaware corporation (Purchaser) and a wholly owned subsidiary of Parent. Pursuant to the Merger Agreement, on August 20, 2011, Purchaser accepted for payment all of the outstanding shares of the Company s common stock, par value $0.001 per share, validly tendered and not validly withdrawn pursuant to the tender offer for $38.75 per share (Offer Price), net to the seller in cash. Additionally, and pursuant to the Merger Agreement, on August 25, 2011, Purchaser merged with and into Petrohawk, with Petrohawk continuing as the surviving corporation in the merger and as a wholly owned subsidiary of Parent (the BHP Merger). Although the Company is a wholly owned subsidiary of BHP Billiton Limited, the Company has not established a new basis of accounting as such push down accounting from BHP Billiton Limited was deemed inappropriate for the Company s consolidated financial statements due to the nature of Petrohawk s agreement with the bondholders. Thus, the consolidated financial statements are based on the Company s historical accounting activities and do not reflect the acquisition of the Company by BHP Billiton Limited or any of the fair value allocations that were performed in conjunction with the business combination accounting performed by BHP Billiton Limited.

At Parent s request and direction and as an inducement to Parent s willingness to enter into the Merger Agreement, the Company entered into retention agreements (Retention Agreements) with certain of the Company s executive officers contemporaneously with the execution of the Merger Agreement. The Retention Agreements continued the employment of each executive with the Company for a period of time following closing. Floyd C. Wilson also entered into a consulting agreement (Consulting Agreement) with the Company beginning after the retention date specified in Mr. Wilson s Retention Agreement and ending six months thereafter under which Mr. Wilson provided services to the Company and pursuant to which he was entitled to separately specified compensation. Additional information regarding the Merger Agreement, Retention Agreements and Consulting Agreement is set forth in the Company s Form 8-K filed on July 20, 2011.

The company incurred approximately $106.9 million in charges related to the BHP Merger during the year ended December 31, 2011. These costs are reported in *General and administrative* on the consolidated statements of operations.

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 Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company s operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company s consolidated financial statements.

Accounts Receivable and Allowance for Doubtful Accounts

The Company s accounts receivables are primarily receivables from joint interest owners and oil and natural gas purchasers. Accounts receivables from joint interest owners are recorded at the amount due, less an 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 collectability and establishes or adjusts the allowance as necessary using the specific identification method. The allowance for doubtful accounts at December 31, 2012 and 2011, was approximately $2.6 million and $3.1 million, respectively.

Oil and Natural Gas Properties

The Company accounts for its oil and natural gas producing activities using the full cost method of accounting as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural 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 natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling test 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 the Company has made a determination as to the existence of proved reserves. The Company reviews its unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization and the full cost ceiling test limitation.

Gas Gathering Systems and Equipment and Other Operating Assets

Gas gathering systems and equipment are recorded at cost. Depreciation is calculated using the straight-line method over a 30-year estimated useful life. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are 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 Company did not capitalize any interest related to the construction of the Company s gas gathering systems and equipment for the year ended December 31, 2012, and capitalized $1.9 million of interest for the year ended December 31, 2011.

The contribution of the Company s Haynesville Shale gas gathering and treating business to KinderHawk Field Services LLC (KinderHawk) on May 21, 2010 for a 50% membership interest and approximately $917 million in cash is accounted for in accordance with ASC Subtopic 360-20, *Property, Plant and Equipment Real Estate Sales* (ASC 360-20). Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *Gas gathering systems and equipment* and depreciated over the remaining useful life of the assets. Contributions to KinderHawk from the Company and the joint venture partner were recorded as increases in *Gas gathering systems and equipment* on the consolidated balance sheets. On July 1, 2011, the Company transferred its remaining 50% membership interest in KinderHawk to KM Gathering LLC (KM Gathering).

On July 1, 2011, the Company transferred a 25% interest in EagleHawk Field Services LLC (EagleHawk) to KM Eagle Gathering LLC (Eagle Gathering). The EagleHawk transaction is accounted for in accordance with ASC 360-20. Under the financing method, the historical cost of the Eagle Ford Shale gas gathering systems contributed to EagleHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *Gas gathering systems and equipment* and depreciated over the remaining useful life of the assets. Contributions to EagleHawk from the Company and the joint venture partner are recorded as increases in *Gas gathering systems and equipment* on the consolidated balance sheets.

See Note 2, *Acquisitions and Divestitures* for more details regarding the KinderHawk and EagleHawk joint venture arrangements and for discussion of the accounting treatment related to the arrangements.

Gas gathering systems and equipment as of December 31, 2012 and 2011 consisted of the following:

	December 31, 2012	December 31, 2011
	(In thousands)	
Gas gathering systems and equipment	$ 1,348,822	$ 918,810
Less accumulated depreciation	(66,461)	(33,162)
Net gas gathering systems and equipment	$ 1,282,361	$ 885,648

(1) Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *Gas gathering systems and equipment* and depreciated over the remaining useful life of the assets. As of December 31, 2012 and 2011, the table above includes approximately $405.4 million and $420.0 million, respectively, attributed to the net carrying value of the assets contributed to KinderHawk.

(2) Under the financing method, the historical cost of the Eagle Ford Shale gas gathering systems contributed to EagleHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *Gas gathering systems and equipment* and depreciated over the remaining useful life of the assets. As of December 31, 2012 and 2011, the table above includes approximately $715.3 million and $437.3 million, respectively, attributed to the net carrying value of the assets contributed to EagleHawk.

Other operating property and equipment are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: automobiles, leasehold improvements, furniture and equipment, five years or lesser of lease term; rental equipment and capitalized software implementation costs, seven years; and computers, three years. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are 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 Company reviews its gas gathering systems and equipment and other operating assets in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate gas gathering systems and equipment and other operating assets as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of its gas gathering systems and equipment and other operating assets at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Payable on Financing Arrangements

The contribution of the Company s Haynesville Shale gas gathering and treating business to KinderHawk on May 21, 2010 for a 50% membership interest and approximately $917 million in cash is accounted for in accordance with ASC 360-20. Due to the gathering agreement entered into with the formation of KinderHawk, which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of the Company s Haynesville Shale gathering and treating system to form KinderHawk is accounted for as a failed sale of in substance real estate. See Note 2, *Acquisitions and Divestitures* for more details regarding the KinderHawk joint venture arrangement and for discussion of the accounting treatment related to the arrangement. Under the financing method for a failed sale of in substance real estate, on May 21, 2010, the Company recorded a financing obligation on the consolidated balance sheets in *Payable on financing arrangements,* in the amount of approximately $917 million. Reductions to the obligation and the non-cash interest on the financing obligation are tied to the gathering and treating services, as the Company delivers natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to the joint venture partner, and interest is limited up to an amount that is calculated based upon the Company s weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *Interest expense and other* on the consolidated statements of operations. On July 1, 2011, the Company transferred its remaining 50% membership interest in KinderHawk to KM Gathering. See further discussion in Note 2, *Acquisitions and Divestitures.* As a result of the transfer on July 1, 2011, the Company recorded an increase in its financing obligation associated with KinderHawk of approximately $743.0 million.

The Company s transfer of a 25% interest in EagleHawk on July 1, 2011 to Eagle Gathering is accounted for in accordance with ASC 360-20. Due to the gathering agreements which constitute extended continuing involvement under ASC 360-20, it has been determined that the transfer of the Company s Eagle Ford Shale gathering and treating systems to EagleHawk is accounted for as a failed sale of in substance real estate. See Note 2, *Acquisitions and Divestitures* for more details regarding the EagleHawk joint venture arrangement and for discussion of the accounting treatment related to the arrangement. Under the financing method for a failed sale of in substance real estate, on July 1, 2011, the Company recorded a financing obligation on the consolidated balance sheets in *Payable on financing arrangements,* in the amount of approximately $93 million. Reductions to the obligation and the non-cash interest on the financing obligation are tied to the gathering and treating services, as the Company delivers natural gas through the Eagle Ford Shale gathering and treating systems. Interest and principal are determined based upon the allocable income to the joint venture partner, and interest is limited up to an amount that is calculated based upon the Company s weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal.

The balance of the Company s financing obligations as of December 31, 2012 and 2011, was approximately $1.9 billion and $1.8 billion, respectively, of which approximately $19.5 million and $17.6 million was classified as current for the respective periods.

Restricted Cash

In conjunction with the termination of the EagleHawk Revolving Credit Agreement during the fourth quarter of 2011, as discussed in Note 4, *Long-Term Debt,* EagleHawk began issuing cash calls in accordance with each party s membership interest to the Company and Kinder Morgan in order to fund EagleHawk s capital expenditures needs. Since EagleHawk s cash balances are restricted for the purpose of funding its capital program, the Company presented EagleHawk s cash of approximately $23.5 million and $34.7 million as *Restricted cash* at December 31, 2012 and 2011, respectively. Additionally, from time to time, the Company may be requested to escrow certain disputed royalty funds, and as a result, the Company presented cash of approximately $4.1 million as *Restricted Cash* at December 31, 2012.

Discontinued Operations

Certain amounts related to the Company s Fayetteville Shale midstream operations and other operating assets have been reclassified to discontinued operations for all relevant periods presented. Unless otherwise noted, information contained in the notes to the consolidated financial statements relates to the Company s continuing operations. See Note 12, *Discontinued Operations,* for further discussion of the presentation of the Company s Fayetteville Shale midstream and other operating assets as discontinued operations.

Revenue Recognition

Revenues from the sale of crude oil, natural gas and natural gas liquids are recognized when the product is delivered at a fixed or determinable price, title has transferred, collectability is reasonably assured and evidenced by a contract. The Company follows the sales method of accounting for its oil and natural gas revenue, so it recognizes revenue on all crude oil, natural gas, and natural gas liquids sold to purchasers, regardless of whether the sales are proportionate to its ownership in the property. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves.

Marketing Revenue and Expense

Historically, for Louisiana and Arkansas production, a subsidiary of the Company purchased and sold the Company s own and third party natural gas produced from wells which the Company and third parties operated. The revenues and expenses related to these marketing activities were reported on a gross basis as part of operating revenues and operating expenses in historical periods. Marketing revenues were recorded at the time natural gas was physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases were recorded as the subsidiary of the Company took physical title to natural gas and transported the purchased volumes to the point of sale. Effective July 1, 2011, the Company s marketing subsidiary substantially decreased its marketing operations. As a result, certain items previously recorded to *Marketing revenues* will no longer be reported while others will now be recorded to *Oil and natural gas revenues* on the consolidated statements of operations. In addition, certain charges previously reported in *Marketing expenses* will no longer be recorded while others will now be recorded to *Gathering, transportation and other* on the consolidated statements of operations.

Midstream Revenues

Revenues from the Company s midstream operations are derived from providing gathering and treating services for the Company and other owners in wells which the Company and third parties operate. Revenues are recognized when services are provided at a fixed or determinable price, collectability is reasonably assured and evidenced by a contract. The Company s midstream operations does not take title to the natural gas for which services are provided, with the exception of imbalances that are monthly cash settled. The imbalances are recorded using published natural gas market prices.

The contribution of the Company s Haynesville Shale gas gathering and treating business to KinderHawk on May 21, 2010 for a 50% membership interest and approximately $917 million in cash is accounted for in accordance with ASC 360-20. Under the financing method for a failed sale of in substance real estate, the Company recorded KinderHawk s revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to the Company, on the consolidated statements of operations in *Midstream revenues.* On July 1, 2011, following the transfer of the Company s remaining 50% membership interest in KinderHawk to KM Gathering, KinderHawk s revenues are no longer recorded in the Company s consolidated statements of operations in *Midstream revenues.*

The Company s transfer of a 25% interest in EagleHawk on July 1, 2011, to Eagle Gathering is accounted for in accordance with ASC 360-20. Under the financing method for a failed sale of in substance real estate, the Company records EagleHawk s revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to the Company, on the consolidated statements of operations in *Midstream revenues.*

See Note 2, *Acquisitions and Divestitures* for more details regarding the KinderHawk and EagleHawk joint venture arrangements and for discussion of the accounting treatment related to the arrangements.

Concentrations of Credit Risk

The Company operates a substantial portion of its oil and natural 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 natural gas producers. If the oil and natural 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 natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts. In 2012, two of the individual purchasers of the Company s production accounted for in excess of 10% of our total sales. Four individual purchasers of the Company s production collectively represented approximately 42% of the Company s total sales. In 2011, none of the Company s individual purchasers of its production accounted for in excess of 10% of the Company s total sales. Four individual purchasers of the Company s production collectively represented 28% of the Company s total sales. In 2010, none of the Company s individual purchases of its production accounted for in excess of 10% of its total sales. Three individual purchasers of the Company s production each accounted for approximately 9% of its total sales, collectively representing 27% of the Company s total sales.

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.

The Company follows ASC 740, *Income Taxes* (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the consolidated financial statements.

The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

The Company includes interest and penalties relating to uncertain tax positions within *Interest expense and other* on the Company s consolidated statements of operations. Refer to Note 10, *Income Taxes* , for more details.

Generally, the Company s tax years 2007 through 2011 are either currently under audit or remain open and subject to examination by federal tax authorities or the tax authorities in Arkansas, Louisiana, New Mexico, Oklahoma and Texas, which are the jurisdictions in which the Company has had its principal operations. In certain of these jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination. Additionally, it is important to note that years are technically open for examination until the statute of limitations in each respective jurisdiction expires.

Tax audits may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which may be due upon the conclusion of these audits. Estimates of these tax liabilities are made based upon prior experience and are updated for changes in facts and circumstances. However, due to the uncertain and complex application of tax regulations, it is possible that the ultimate resolution of audits may result in liabilities which could be materially different from these estimates.

Asset Retirement Obligation

ASC 410, *Asset Retirement and Environmental Obligations* (ASC 410) 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. The Company records asset retirement obligations to reflect the Company s legal obligations related to future plugging and abandonment of its oil and natural gas wells and gas gathering systems and equipment. The Company estimates the expected cash flow associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. 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, the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells and gas gathering systems and equipment 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 an acquisition. ASC 350, *Intangibles Goodwill and Other* (ASC 350) 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 that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units.

In September 2011, the Financial Accounting Standards Board issued ASU No. 2011-08, *Testing Goodwill for Impairment* (ASU 2011-08) to simplify how companies test goodwill for impairment. ASU 2011-08 simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying amount. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then the entity does not have to perform the two-step impairment test. However, if that same conclusion is not reached, the company is required to perform the first step of the two-step impairment test. ASU 2011-08 also allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test. The first step is to compare the fair value of a reporting unit with its carrying value, including goodwill. If the fair value of a reporting unit is less than its carrying value, then the second step of the test must be performed to measure the amount of the impairment loss, if any.

The Company performs its goodwill test annually during the third quarter or more often if circumstances require. During the third quarter of 2012, the Company elected to first assess qualitative factors. The qualitative assessment included an evaluation of factors such as macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, as well as other relevant events and circumstances that affect the fair value or carrying amount. Based on this qualitative assessment, there was no impairment indicators that would indicate that it is more likely than not that the fair value of the Company s oil and gas reporting unit is less than its carrying amount. As such, the Company did not perform the two-step goodwill impairment test during 2012. In previous years, the Company s goodwill impairment review consisted of a two-step process. The first step is to determine the fair value of its reporting unit and compare it to the carrying value of the related net assets. Fair value is determined based on the Company s estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write down is required. The second step is required if the fair value of the Company s reporting unit is less than the carrying value of the net assets. In this step the implied fair value of the Company s reporting unit is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written down to its implied fair value. If the fair value of the Company s reporting unit 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 against earnings. The assumptions used by the Company in calculating its reporting unit fair values at the time of the test in prior years included the Company s market capitalization and discounted future cash flows based on estimated reserves and production, future development and operating costs and future oil and natural gas prices. Material adverse changes to any of the factors considered could lead to an impairment of all or a portion of the Company s goodwill in future periods.

The Company completed its annual goodwill impairment test during the third quarters of 2012, 2011 and 2010. Based on these reviews, no goodwill impairments were deemed necessary.

Other Intangible Assets

The Company treats the costs associated with acquired transportation contracts as intangible assets which will be amortized over the life of the extended agreement. The initial amount recorded represents the fair value of the contract at the time of acquisition, which is amortized under the straight-line method over the life of the contract. Any unamortized balance of the Company s intangible assets will be subject to impairment testing pursuant to the *Impairment or Disposal of Long-Lived Assets* Subsections of ASC Subtopic 360-10 (ASC 360-10). The Company reviews its intangible assets for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred.

Amortization expense was $11.1 million for the years ended December 31, 2012, 2011 and 2010, and was allocated to operating expenses between *Marketing* and *Gathering, transportation and other* on the consolidated statements of operations based on the usage of the contract. Effective July 1, 2011 and in conjunction with the elimination of the Company s marketing activities, this amortization will be included in *Gathering, transportation and other* only.

During 2012, one acquired transportation contract (the Kaiser contract) for gas export from the Haynesville field reached a point at which the Company has the option to cancel or extend the contract at its sole discretion. Due to the changes in the gas market since the time of acquisition and the availability of alternative transportation routes, the decision was made not to extend this contract. As a result, a change in circumstances was noted and the remaining net book value of approximately $67.2 million associated with the Kaiser contract was impaired.

Intangible assets subject to amortization at December 31, 2012 and 2011 are as follows:

	December 31,	
	2012	2011
	(In thousands)	
Transportation contracts	$ 105,108	$ 105,108
Less accumulated amortization	(37,871)	(26,819)
Less impairment of Kaiser contract	(67,237)	
Net transportation contracts	$	$ 78,289

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 employees of the Company who are 21 years of age are eligible to participate. The Company charged to expense plan contributions of $6.4 million, $5.8 million and $4.3 million in 2012, 2011 and 2010, respectively. The Company matches employee contributions dollar-for-dollar on the first 10% of an employee s pretax earnings.

Subsequent to December 31, 2012, all employees are included in BHP Billiton Limited s benefits program for Petroleum employees in the USA and are eligible to participate in the BHP Billiton Limited 401(k) plan.

Recently Issued Accounting Pronouncements

In September 2011, the FASB issued ASU No. 2011-08, *Testing Goodwill for Impairment* (ASU 2011-08) to simplify how companies test goodwill for impairment. ASU 2011-08 simplifies testing for goodwill impairments by allowing entities to first assess qualitative factors to determine whether the facts or circumstances lead to the conclusion that it is more likely than not that the fair value of a reporting unit is less than the carrying amount. If the entity concludes that it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then the entity does not have to perform the two-step impairment test. However, if that same conclusion is not reached, the company is required to perform the first step of the two-step impairment test. In this step, the fair value of the reporting unit is calculated and compared to the carrying amount of the reporting unit. If the carrying amount exceeds the fair value, then the entity must perform the second step of the impairment test to measure the amount of the impairment loss, if any. ASU 2011-08 allows a company to bypass the qualitative assessment and proceed directly with performing the two-step goodwill impairment test. ASU 2011-08 is effective for annual and interim goodwill impairment tests for fiscal years beginning after December 15, 2011 and early adoption is permitted. The Company adopted the provisions of ASU 2011-08 in its goodwill impairment test conducted in the third quarter of 2012. See further discussion above under the heading *Goodwill* .

In December 2011, the FASB issued ASU No. 2011-11, *Disclosures About Offsetting Assets and Liabilities* (ASU 2011-11). Due to differences between GAAP and IFRS related to the requirements for offsetting (netting) assets and liabilities in a company s financial statements, ASU 2011-11 requires additional disclosures about the netting of assets and liabilities. ASU 2011-11 is intended to facilitate the comparison of financial statements prepared in accordance with GAAP and IFRS. Under ASU 2011-11, companies are required to present both gross and net information about transactions and instruments eligible for offset in the balance sheet, as well as transactions and instruments subject to an agreement similar to a master netting arrangement. Examples of such transactions and instruments include derivatives, sale and repurchase agreements and reverse sale and repurchase agreements, and securities borrowing and securities lending arrangements. ASU 2011-11 becomes effective with annual reporting periods after January 1, 2013 (and interim periods within the annual reporting period) and companies will be required to show the disclosures required by ASU 2011-11 retrospectively for all comparative periods presented. The Company is currently assessing the impact, if any, that ASU 2011-11 will have on its disclosures.

In July 2012, the FASB issued ASU 2012-02, *Intangibles-Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment* (ASU 2012-02). This guidance is intended to simplify the impairment test for indefinite-lived intangible assets other than goodwill by giving entities the option to first assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. The results of the qualitative assessment would be used as a basis in determining whether it is necessary to perform the two-step quantitative impairment testing. An entity can choose to perform the qualitative assessment on none, some or all of its indefinite-lived intangible assets, or may bypass the qualitative assessment and proceed directly to the quantitative impairment test. This guidance will be effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted in certain circumstances. As the Company does not currently have any indefinite-lived intangible assets, this guidance will have no impact on its operating results, financial position, cash flows and disclosures.

2. ACQUISITIONS AND DIVESTITURES

Acquisitions

CEU Hawkville, LLC

On December 22, 2011, we completed the acquisition of CEU Hawkville, LLC (CEU Hawkville Acquisition), which we purchased all of the outstanding membership interests in CEU Hawkville for $90 million, before customary closing adjustments. CEU Hawkville s assets consist primarily of interests in oil and natural gas properties in the Hawkville Field of the Eagle Ford Shale. The transaction had an effective date of October 1, 2011. Upon closing of the transaction, the Company changed the name of CEU Hawkville, LLC to South Texas Shale LLC.

The CEU Hawkville Acquisition was accounted for using the purchase method of accounting under ASC 805, *Business Combinations* (ASC 805). The Company reflected the results of operations of CEU Hawkville beginning December 22, 2011. The Company recorded the fair values of the assets acquired and liabilities assumed at December 22, 2011, which primarily consisted of oil and natural gas properties of $90.1 million and asset retirement obligations of $0.3 million. As a result, the assets and liabilities of CEU Hawkville were included in the Company s December 31, 2011 consolidated balance sheet.

Divestitures

Midstream Transactions

On July 1, 2011, the Company closed previously announced transactions with KM Gathering and Eagle Gathering, each of which is an affiliate of Kinder Morgan Energy Partners, L.P., a publicly traded master limited partnership (Kinder Morgan), in which Hawk Field Services LLC (Hawk Field Services) transferred (i) its remaining 50% membership interest in KinderHawk to KM Gathering and (ii) a 25% interest in EagleHawk to Eagle Gathering, in exchange for aggregate cash consideration of approximately $836 million. In conjunction with the closing of the transactions, the balance of the Company s capital commitment to KinderHawk, approximately $41.4 million as of July 1, 2011, was relieved. The Company s commitment to deliver certain minimum annual quantities of natural gas through the Haynesville gathering system through May 2015 was not relieved in the transfer. The effective date of the transactions is July 1, 2011. See *Hawk Field Services, LLC Joint Venture* below for more details regarding the initial joint venture arrangement between Hawk Field Services and Kinder Morgan and for discussion of the accounting treatment for both KinderHawk transactions.

EagleHawk engages in the natural gas midstream business in the Eagle Ford Shale in South Texas. EagleHawk holds the Company s gathering and treating assets and business serving the Company s Hawkville and Black Hawk Fields in the Eagle Ford Shale. EagleHawk has agreements with the Company covering gathering and treating of natural gas and transportation of condensate and pursuant to which the Company dedicates its production from its Eagle Ford Shale leases. Hawk Field Services manages EagleHawk s operations.

The EagleHawk joint venture is accounted for as a failed sale of in substance real estate under the provisions of ASC 360-20. ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller s business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Eagle Ford Shale gathering and treating systems, consist of right of ways, pipelines and processing facilities. Due to the gathering agreements which constitute extended continuing involvement under ASC 360-20, it has been determined that the transfer of the Company s Eagle Ford Shale gathering and treating systems to EagleHawk should be accounted for as a failed sale of in substance real estate.

As a result of the failed sale, the Company accounts for the continued operations of the gas gathering systems and reflects a financing obligation, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Eagle Ford Shale gas gathering systems transferred to EagleHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *Gas gathering systems and equipment* and depreciated over the remaining useful life of the assets. The financing obligation of approximately $213 million as of December 31, 2012, is recorded on the consolidated balance sheets in *Payable on financing arrangements.* Reductions to the obligation and non-cash interest on the financing obligation are tied to the gathering and treating services, as the Company delivers its production through the Eagle Ford Shale gathering and treating systems. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon the Company s weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *Interest expense and other* on the consolidated statements of operations. Additionally, the Company records EagleHawk s revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to the Company, and expenses on the consolidated statements of operations in *Midstream revenues, Taxes other than income, Gathering, transportation and other, General and administrative, Interest expense and other* and *Depletion, depreciation and amortization.*

Fayetteville Shale

On December 22, 2010, the Company completed the sale of its interest in natural gas properties and other operating assets in the Fayetteville Shale for $575 million in cash, before customary closing adjustments. Proceeds from the sale of the interest in natural gas properties were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. In conjunction with the sale of the other operating assets, the Company recorded a loss of approximately $0.5 million in the year ended December 31, 2010. On January 7, 2011, the Company completed the sale of its midstream assets in the Fayetteville Shale for approximately $75 million in cash, before customary closing adjustments. As of December 31, 2010, the Fayetteville Shale midstream assets were classified as *Assets held for sale* on the Company s consolidated balance sheet. *Assets held for sale* were recorded at the lesser of the carrying amount or the fair value less costs to sell, which resulted in a write down of the carrying amount of approximately $69.7 million in the year ended December 31, 2010. Both transactions had an effective date of October 1, 2010.

Mid-Continent Properties

On September 29, 2010, the Company completed the sale of its interest in certain Mid-Continent properties in Texas, Oklahoma and Arkansas for $123 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. The transaction had an effective date of July 1, 2010.

Hawk Field Services, LLC Joint Venture

On May 21, 2010, Hawk Field Services and Kinder Morgan formed a joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The joint venture entity, KinderHawk, was engaged in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower Bossier Shales. Pursuant to the Contribution Agreement, Hawk Field Services contributed to KinderHawk its Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $917 million in cash ($875 million for a 50% membership interest in KinderHawk and $42 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. Upon the completion of the transaction both the Company and Kinder Morgan held a 50% membership interest in KinderHawk. KinderHawk distributed approximately $917 million to Hawk Field Services. The joint venture had an economic effective date of January 1, 2010, and Hawk Field Services continued to operate the business until September 30, 2010, at which date Hawk Field Services and Kinder Morgan terminated the transition services agreement and KinderHawk assumed operations of the joint venture. On July 1, 2011, the Company transferred its remaining 50% membership interest in KinderHawk to KM Gathering.

The Company is obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from Petrohawk operated wells producing from the Haynesville and Lower Bossier Shales with specified acreage in Northwest Louisiana through May 2015. In addition, the Company pays an annual fee to KinderHawk if such minimum annual quantities are not delivered, and for the year ended December 31, 2012, no such fee has been paid. The Company pays KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. The gathering fee at the time the Company entered into the contract was equal to $0.34 per thousand cubic feet (Mcf) of natural gas delivered at KinderHawk s receipt points. The treating fee is charged for gas delivered containing more than 2% by volume of carbon dioxide. For gas delivered containing between 2% and 5.5% carbon dioxide, the treating fee is between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee starts at $0.365 per Mcf and increases on a scale of $0.09 per Mcf for each additional 1% of carbon dioxide content. The Company s obligation to deliver minimum annual quantities of natural gas to KinderHawk through May 2015 remained in effect following the transfer of the Company s remaining 50% membership interest in KinderHawk on July 1, 2011.

The KinderHawk joint venture is accounted for as a failed sale of in substance real estate under the provisions of ASC 360-20. ASC 360-20 establishes standards for recognition of profit on all real estate sales transactions other than retail land sales, without regard to the nature of the seller s business. In making the determination of whether a transaction qualifies, in substance, as a sale of real estate, the nature of the entire real estate being sold is considered, including the land plus the property improvements and the integral equipment. The Haynesville Shale gathering and treating system, consists of right of ways, pipelines and processing facilities. Due to the gathering agreement which constitutes extended continuing involvement under ASC 360-20, it has been determined that the contribution of the Company s Haynesville Shale gathering and treating system to form KinderHawk should be accounted for as a failed sale of in substance real estate.

As a result of the failed sale, the Company accounts for the continued operations of the gas gathering system and reflects a financing obligation, representing the proceeds received, under the financing method of real estate accounting. Under the financing method, the historical cost of the Haynesville Shale gas gathering system contributed to KinderHawk is carried at the full historical basis of the assets on the consolidated balance sheets in *Gas gathering systems and equipment* and depreciated over the remaining useful life of the assets. The financing obligation of approximately $1.7 billion as of December 31, 2012, is recorded on the consolidated balance sheets in *Payable on financing arrangements.* Reductions to the obligation and non-cash interest on the financing obligation are tied to the gathering and treating services, as the Company delivers natural gas through the Haynesville Shale gathering and treating system. Interest and principal are determined based upon the allocable income to Kinder Morgan, and interest is limited up to an amount that is calculated based upon the Company s weighted average cost of debt as of the date of the transaction. Allocable income in excess of the calculated value is reflected as reductions of principal. Interest is recorded in *Interest expense and other* on the consolidated statements of operations. Additionally, the Company recorded KinderHawk s revenues, net of eliminations for intercompany amounts associated with gathering and treating services provided to the Company, and expenses on the consolidated statements of operations in *Midstream revenues,* *Taxes other than income,* *Gathering, transportation and other,* *General and administrative,* *Interest expense and other* and *Depletion, depreciation and amortization.*

On July 1, 2011, following the transfer of the Company s remaining 50% membership interest in KinderHawk to KM Gathering, KinderHawk s revenues and expenses are no longer recorded in the Company s consolidated statements of operations. The historical cost of the Haynesville Shale gas gathering system continues to be carried at the full historical basis of the assets on the consolidated balance sheet and depreciated over the useful life of the assets.

Terryville

On May 12, 2010, the Company completed the sale of its interest in Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana for $320 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. The transaction had an effective date of January 1, 2010. In conjunction with the closing, the Company deposited $75 million with a qualified intermediary to facilitate like-kind exchange transactions all of which had been spent as of December 31, 2010.

West Edmond Hunton Lime Unit

On April 30, 2010, the Company completed the sale of its interest in the West Edmond Hunton Lime Unit (WEHLU) in Oklahoma County, Oklahoma for $155 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. The transaction had an effective date of April 1, 2010.

3. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2012 and 2011, consisted of the following:

	December 31,	
	2012	**2011**
	(In thousands)	
Subject to depletion	$ 13,213,484	$ 10,509,954
Not subject to depletion:		
Exploration and extension wells in progress	399,672	75,635
Other capital costs:		
Incurred in 2012	169,782	
Incurred in 2011	697,854	728,987
Incurred in 2010	379,796	421,759
Incurred in 2009	301,101	319,656
Incurred in 2008 and prior	891,745	956,398
Total not subject to depletion	2,839,950	2,502,435
Gross oil and natural gas properties	16,053,434	13,012,389
Less accumulated depletion	(6,708,875)	(5,598,420)
Net oil and natural gas properties	$ 9,344,559	$ 7,413,969

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion exceed the discounted future net revenues of proved oil and natural gas reserves net of deferred taxes, such excess capitalized costs are charged to expense. Beginning December 31, 2009, full cost companies use the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date.

The Company assesses all items classified as unevaluated property on a periodic basis for possible impairment or reduction in value. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization and the full cost ceiling test limitation.

At December 31, 2012, the ceiling test value of the Company s reserves was calculated based on the first day average of the 12-months ended December 31, 2012, of the West Texas Intermediate (WTI) spot price of $94.89 per barrel or was calculated based equally on the respective first day average of the 12-months ended December 31, 2012, of the WTI spot price of $94.89 per barrel and the Light Louisiana Sweet (LLS) spot price of $111.79 per barrel, depending on location and adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2012 of the Henry Hub price of $2.78 per million British thermal units (Mmbtu), adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, the Company s net book value of oil and natural gas properties at December 31, 2012 did not exceed the ceiling amount. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company s actual ceiling test calculation and impairment analyses in future periods.

At December 31, 2011 the ceiling test value of the Company s reserves was calculated based on the first day average of the 12-months ended December 31, 2011 of the West Texas Intermediate (WTI) spot price of $96.19 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2011 of the Henry Hub price of $4.12 per million British thermal units (Mmbtu), adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, the Company s net book value of oil and natural gas properties at December 31, 2011 did not exceed the ceiling amount.

At December 31, 2010 the ceiling test value of the Company s reserves was calculated based on the first day average of the 12-months ended December 31, 2010 of the WTI spot price of $79.43 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2010 of the Henry Hub price of $4.38 per Mmbtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, the Company s net book value of oil and natural gas properties at December 31, 2010 did not exceed the ceiling amount.

4. LONG-TERM DEBT

Long-term debt as of December 31, 2012 and 2011 consisted of the following:

	December 31,	
	2012	**2011***(1)*
	(In thousands)	
6.25% $600 million senior notes*(2)*	$ 600,000	$ 600,000
7.25% $1.2 billion senior notes*(3)*	1,230,942	1,231,780
10.5% $600 million senior notes*(4)*	571,208	561,250
7.875% $800 million senior notes	799,611	799,611
	$ 3,201,761	$ 3,192,641

(1) Amounts exclude $17.5 million of deferred premiums on derivative contracts which had been classified as current at December 31, 2011.

(2) On May 20, 2011, the Company issued $600 million principal amount of its 6.25% senior notes due 2019. See *6.25% Senior Notes* below for more details.

(3) On August 17, 2010 and January 31, 2011, the Company issued an initial $825 million principal amount and an additional $400 million principal amount, respectively, of its 7.25% senior notes due 2018. Amount includes a $5.9 million and $6.8 million premium at December 31, 2012, and 2011, respectively, recorded by the Company in conjunction with the issuance of the additional $400 million principal amount. See *7.25% Senior Notes* below for more details.

(4) Amount includes an $18.4 million and $28.4 million discount, at December 31, 2012 and 2011, respectively, which was recorded by the Company in conjunction with the issuance of the 10.5% senior notes due 2014. See *10.5% Senior Notes* below for more details.

Senior Revolving Credit Facility

Historically, the Company had a credit facility between the Company, each of the lenders from time to time party thereto (the Lenders), BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders (the Senior Credit Agreement). Effective October 3, 2011, the Company reduced the borrowing base under its Senior Credit Agreement from $2.5 billion to $25 million. At December 31, 2011, the Company had a $3.0 million letter of credit outstanding with a vendor, no borrowings outstanding and $22.0 million of borrowing capacity under the Senior Credit Agreement. Effective February 1, 2012, the $3.0 million letter of credit was terminated and effective March 13, 2012, the Company terminated the Senior Credit Agreement.

The Company s primary sources of capital and liquidity have historically been internally generated cash flows from operations, proceeds from asset sales and availability under the Senior Credit Agreement. Due to the termination of the Company s Senior Credit Agreement, future capital resources and liquidity will now be from equity funding by the Parent and the Company s internally generated cash flows from operations.

EagleHawk Revolving Credit Facility

On July 1, 2011, EagleHawk, each of the lenders from time to time party hereto (the EagleHawk Lenders), and Wells Fargo Bank, N.A., as administrative agent for the EagleHawk Lenders, entered into a Revolving Credit Agreement (the EagleHawk Revolving Credit Agreement). The EagleHawk Revolving Credit Agreement provided for up to a $250 million credit facility with initial availability of $75 million. On November 1, 2011, EagleHawk repaid all outstanding borrowings under the EagleHawk Revolving Credit Agreement and terminated the facility.

6.25% Senior Notes

On May 20, 2011, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million of its 6.25% senior notes due 2019 (the 2019 Notes). The 2019 Notes were issued under and are governed by an indenture dated May 20, 2011, between the Company, U.S. Bank Trust National Association, as trustee, and the Company s subsidiaries named therein as guarantors (the 2019 Indenture). The 2019 Notes were sold to investors at 100% of the aggregate principal amount of the 2019 Notes. The net proceeds from the sale of the 2019 Notes were approximately $589 million (after deducting offering fees and expenses). The proceeds were used to repay borrowings outstanding under the Company s senior revolving credit facility and for working capital for general corporate purposes.

The 2019 Notes bear interest at a rate of 6.25% per annum, payable semi-annually on June 1 and December 1 of each year, commencing on December 1, 2011. The 2019 Notes will mature on June 1, 2019. The 2019 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2019 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company s subsidiaries, with the exception of two subsidiaries, as discussed in Note 13, *EagleHawk Field Services.* Petrohawk Energy Corporation, the issuer of the 2019 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On or prior to June 1, 2014, the Company may redeem up to 35% of the aggregate principal amount of the 2019 Notes with the net cash proceeds of certain equity offerings at a redemption price of 106.25% of the principal amount, plus accrued and unpaid interest to the redemption date; provided that at least 65% in aggregate principal of the 2019 Notes originally issued under the 2019 Indenture remain outstanding immediately after the redemption. In addition, on or prior to June 1, 2015, the Company may redeem all or part of the 2019 Notes at a redemption price equal to the principal amount, plus accrued and unpaid interest, plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at June 1, 2015 plus (ii) any required interest payments due on such note through June 1, 2015 (except for currently accrued and unpaid interest), computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months), over (b) the principal amount of such Note.

On or after June 1, 2015, the Company may redeem all or a part of the 2019 Notes at any time or from time to time, at the redemption prices (expressed as percentages of principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning on June 1 of the years indicated below:

Year	Percentage
2015	103.125
2016	101.563
2017	100.000

The Company is required to offer to repurchase the 2019 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2019 Indenture that is followed by a decline within 90 days in the ratings of the 2019 Notes published by either Moody s Investor Service, Inc. (Moody s) or Standard & Poor s Rating Services (S&P). The Company s credit rating did not decline in the allotted period of time after the change of control with the closing of the BHP merger. As a result, no such offer was made. The 2019 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: borrow money; pay dividends on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; and merge with or into other companies or transfer all or substantially all of the Company s assets. However, during the fourth quarter of 2011, an Investment Grade Rating Event (as defined in the 2019 Indenture) occurred that resulted in certain covenants in the 2019 Indenture, including covenants relating to incurrence of indebtedness, restricted payments, asset sales and affiliate transactions, being terminated.

7.25% Senior Notes

On August 17, 2010, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $825 million of its 7.25% senior notes due 2018 (the initial 2018 Notes) at a purchase price of 100% of the principal amount of the initial 2018 Notes. The initial 2018 Notes were issued under and are governed by an indenture dated August 17, 2010, between the Company, U.S. Bank Trust National Association, as trustee, and the Company s subsidiaries named therein as guarantors (the 2018 Indenture). The Company applied the net proceeds from the sale of the initial 2018 Notes to redeem its $775 million 9.125% senior notes due 2013.

On January 31, 2011, the Company completed the issuance of an additional $400 million aggregate principal amount of its 7.25% senior notes due 2018 (the additional 2018 Notes) in a private placement to eligible purchasers. The additional 2018 Notes are issued under the same Indenture and are part of the same series as the initial 2018 Notes. The additional 2018 Notes together with the initial 2018 Notes are collectively referred to as the 2018 Notes.

The additional 2018 Notes were sold to Barclays Capital Inc. at 101.875% of the aggregate principal amount of the additional 2018 Notes plus accrued interest. The net proceeds from the sale of the additional 2018 Notes were approximately $400.5 million (after deducting offering fees and expenses). A portion of the proceeds of the additional 2018 Notes were utilized to redeem all of the Company s outstanding $275 million 7.125% senior notes due 2012.

Interest on the 2018 Notes is payable on February 15 and August 15 of each year, beginning on February 15, 2011. Interest on the 2018 Notes accrued from August 17, 2010, the original issuance date of the series. The 2018 Notes will mature on August 15, 2018. The 2018 Notes are senior unsecured obligations of the Company and rank equally with all of the Company s current and future senior indebtedness. The 2018 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the 2018 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On or prior to August 15, 2013, the Company may redeem up to 35% of the aggregate principal amount of the 2018 Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.25% of the principal amount, plus accrued and unpaid interest to the redemption date; provided that at least 65% in aggregate principal amount of the 2018 Notes originally issued under the 2018 Indenture remain outstanding immediately after the redemption. In addition, at any time prior to August 15, 2014, the Company may redeem some or all of the 2018 Notes for the principal amount, plus accrued and unpaid interest, plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at August 15, 2014, (ii) any required interest payments due on the notes (except for currently accrued and unpaid interest), computed using a discount rate equal to the Treasury Rate plus 50 basis points, discounted to the redemption date on a semi-annual basis, over (b) the principal amount of such note.

On or after August 15, 2014, the Company may redeem all or part of the 2018 Notes at any time or from time to time at the redemption prices (expressed as a percentage of principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning August 15 of the years indicated below:

Year	**Percentage**
2014	103.625
2015	101.813
2016 and thereafter	100.000

The Company is required to offer to repurchase the 2018 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2018 Indenture that is followed by a decline within 90 days in the ratings of the 2018 Notes published by either Moody s or S&P. The Company s credit rating did not decline in the allotted period of time after the change of control with the closing of the BHP merger. As a result, no such offer was made. The 2018 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: borrow money; pay dividends on stock; purchase or redeem stock