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26 September 2013

To: Australian Securities Exchange[1]
London Stock Exchange

cc: New York Stock Exchange
JSE Limited

PETROHAWK TRANSITIONAL REPORT TO SECURITY HOLDERS

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. Petrohawk has changed its balance date to 30 June to align with BHP Billiton's fiscal year. The attached report is a transitional report to Security Holders which covers the six month period ended 30 June 2013 (Transitional Report). A copy of the Transitional Report 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 the Transitional 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 Transitional 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

TRANSITION REPORT TO SECURITY HOLDERS

JUNE 30, 2013

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. This transitional financial report to Security Holders covers the period from January 1, 2013 through June 30, 2013, and includes all information otherwise required in an annual report to bondholders under section 4.2 of the Indentures.

Special note regarding forward-looking statements

This Transition 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 similar terms and phrases. 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 Transition Report contain additional information that should be referred to when reviewing this material.

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. We refer to the resulting transition period from January 1, 2013 through June 30, 2013 in this Transition Report as the six months ended June 30, 2013.

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 hydrocarbons predominately from oil and gas shale 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 predominately 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, capital market issuances of debt and equity, 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 June 30, 2013.

	Payments Due By Period				
Contractual Obligations	**Total**	**2014**	**2015–2016**	**2017–2018**	**2019 and Beyond**
			(In thousands)		
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% $800 million senior notes (4)	799,611	—	799,611	—	—
Interest expense on long-term debt (5)	864,802	251,194	315,506	252,625	45,477
Total debt	4,079,053	251,194	1,704,757	252,625	1,870,477
Gathering and transportation contracts	3,419,304	453,203	839,125	692,062	1,434,914
Rig commitments (6)	692,969	217,109	350,077	116,860	8,923
Pipeline and well equipment	135,726	135,726	—	—	—
Other commitments (7)	31,992	31,992	—	—	—
Operating leases	18,108	9,043	7,544	1,521	—
Total commitments	4,298,099	847,073	1,196,746	810,443	1,443,837
Total contractual obligations	**$ 8,377,152**	**$ 1,098,267**	**$ 2,901,503**	**$ 1,063,068**	**$ 3,314,314**

(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 $5.5 million unamortized premium at June 30, 2013, 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 $13.0 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 June 30, 2013, less required annual repayments.

(6) Includes rig contracts which were cancelled subsequent to June 30, 2013. See Note 7, "*Commitments and Contingencies*" for further details.

(7) Other commitments pertain to exploration, development and production activities.

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 June 30, 2013, we did not have any material off-balance sheet arrangements.

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 prior to the reporting date, 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 as of June 30, 2013, and December 31, 2012, were prepared internally, and our estimated proved reserves as of 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 Annual Report for the year ended December 31, 2012 and 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 $0.13 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 stockholder's 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 June 30, 2013, 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 $2.9 billion before income taxes and $1.8 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 2013 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 $0.07 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 June 30, 2013, 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 quarter ending June 30 or more often if circumstances require. During the quarter ending June 30, 2013, 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 were 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 the six months ended June 30, 2013. 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 June 30, 2013, 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

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

We reported income from continuing operations, net of income taxes, of $5.0 million for the six months ended June 30, 2013, compared to a loss from continuing operations, net of income taxes, of $101.8 million for the comparable period in 2012. The following table summarizes key items of comparison and their related change for the periods indicated.

	Six Months Ended June 30,		
(In thousands (except per unit and per Mcfe amounts))	**2013**	**2012**	**Change**
Income (loss) from continuing operations, net of income taxes	$ 4,976	$ (101,774)	$ 106,750
Operating revenues:			
Oil and natural gas	1,368,117	965,274	402,843
Marketing	99,504	(67)	99,571
Midstream	30,563	40,778	(10,215)
Operating expenses:			
Marketing	99,635	—	99,635
Production:			
Lease operating	83,019	44,291	38,728
Workover and other	16,176	8,243	7,933
Taxes other than income	60,865	29,880	30,985
Gathering, transportation and other	224,027	157,750	66,277
General and administrative	108,320	99,245	9,075
Depletion, depreciation and amortization:			
Depletion – Full cost	588,127	549,989	38,138
Depreciation – Midstream	22,258	15,040	7,218
Depreciation – Other	19,179	11,607	7,572
Accretion expense	2,618	1,428	1,190
Rig contract termination costs	76,528	—	76,528
Impairment of capitalized software costs	—	1,351	(1,351)
Other income (expenses):			
Net gain on derivative contracts	—	(28,260)	28,260
Interest expense and other	(213,112)	(215,413)	2,301
Income (loss) from continuing operations before income taxes	(15,680)	(156,512)	140,832
Income tax benefit (provision)	20,656	54,738	(34,082)
Production:			
Natural gas – Mmcf	162,868	176,422	(13,554)
Crude oil – MBbl	6,668	4,625	2,043
Natural gas liquids – MBbl	4,537	2,656	1,881
Natural gas equivalent – Mmcfe (1)	230,100	220,108	9,992
Average daily production – Mmcfe (1)	1,271	1,209	62
Average price per unit (2):			
Natural gas price – Mcf	$ 3.55	$ 2.27	$ 1.28
Crude oil price – Bbl	99.97	99.33	0.64
Natural gas liquids price – Bbl	26.90	37.34	(10.44)
Natural gas equivalent price – Mcfe (1)	5.94	4.36	1.58
Average cost per Mcfe:			
Production:			
Lease operating	0.36	0.20	0.16
Workover and other	0.07	0.04	0.03
Taxes other than income	0.26	0.14	0.12
Gathering, transportation and other	0.97	0.72	0.25
General and administrative	0.47	0.45	0.02
Depletion	2.56	2.50	0.06

(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 six months ended June 30, 2013, oil and natural gas revenues increased $402.8 million from the same period in 2012, to $1.4 billion. The increase was primarily due to the increase of $1.58 per Mcfe in our realized average price to $5.94 per Mcfe from $4.36 per Mcfe in the prior year period. The increase per Mcfe led to an increase in oil and natural gas revenues of approximately $346.9 million. The increase related to our realized average price was combined with an increase in our production of 9,992 Mmcfe, or 5% over 2012, primarily due to new wells in the Eagle Ford and Haynesville Shales. Increased production contributed approximately $59.3 million in revenues for the six months ended June 30, 2013.

We had marketing revenues of $99.5 million and marketing expenses of $99.6 million for the six months ended June 30, 2013, resulting in a loss before income taxes of $0.1 million. Marketing revenues and expenses are related to the purchase and sale of third party condensate.

We had gross revenues from our midstream business of $75.5 million for the six months ended June 30, 2013, compared to the same period in 2012 of $65.0 million, an increase of $10.5 million. The increase in gross revenues from our midstream business primarily relates to income for gathering services relating to new production and an increase in condensate handling fees due to additional volumes at Eagle Ford. In accordance with the financing method for a failed sale of in substance real estate we record EagleHawk'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 six months ended June 30, 2013, approximately $23.3 million in revenues, after intercompany eliminations, from EagleHawk were reported in midstream revenues on the consolidated statements of operations. Gross revenues of $75.5 million also included $44.9 million of intercompany revenues that were eliminated in consolidation. On a net basis, we had revenues of $30.6 million for the six months ended June 30, 2013, a decrease of $10.2 million from the prior year. This decrease is attributed to declining third party revenues related to gathering, trucking, treating and compression services, respectively.

Lease operating expenses increased $38.7 million for the six months ended June 30, 2013, as compared to the same period in 2012. The increase was primarily due to an increase in the number of wells, combined with increased in production. On a per unit basis, lease operating expenses increased $0.16 per Mcfe to $0.36 per Mcfe in 2013 from $0.20 per Mcfe in 2012, primarily due to higher liquid production mix.

Workover and other expenses increased $7.9 million for the six months ended June 30, 2013, as compared to the same period in 2012. The increase was primarily due to $9.3 million costs during the second quarter of 2013 associated with damage incurred to a rig during drilling operations. This increase was partially offset by a decrease in workover activity during the six months ended June 30, 2013 compared to the same period in 2012.

Taxes other than income increased $31.0 million for six months ended June 30, 2013, as compared to the same period in 2012. 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 six months ended June 30, 2013, we recorded severance tax refunds totaling $6.1 million compared to $17.4 million in the prior year. Severance taxes rose from $39.8 million for the six months ended June 30, 2012 to $50.2 million in the current year. Ad Valorem taxes increased $11.4 million for the six months ended June 30, 2013 compared to the same period in 2012, as a result of an Ad Valorem tax payment in 2013. On a per unit basis, excluding the severance tax refunds, taxes other than income were $0.29 per Mcfe in 2013 compared to $0.21 per Mcfe in 2012.

Gathering, transportation and other expense increased $66.3 million for the six months ended June 30, 2013 as compared to the same period in 2012. On a per unit basis, gathering transportation and other increased $0.25 per Mcfe from $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 six months ended June 30, 2013, increased $9.1 million as compared to the same period in 2012. The increase is primarily attributable to normal increases in payroll and employee costs due to growth over the prior period.

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 $38.1 million for the six months ended June 30, 2013, from the same period in 2012, to $588.1 million. On a per unit basis, depletion expense increased $0.06 per Mcfe to $2.56 per Mcfe. The increase on a per unit basis is primarily due to capital spending during the six months ended June 30, 2013, partially offset by an increase in our reserve volume.

Depreciation expense associated with our gas gathering systems increased $7.2 million to $22.3 million for the six months ended June 30, 2013, as compared to the same period in 2012. 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 $7.6 million to $19.2 million for the six months ended June 30, 2013, as compared to the same period in 2012. The increase is primarily due to accelerated depreciation related to software as Petrohawk is integrated into BHP's accounting software, combined with an increase related to expansion and growth of our capital spending.

During the second quarter of 2013, we made modifications to the number of rigs within our rig fleet. As such, we incurred costs of approximately $70.5 million associated with the early termination of select rig contracts and approximately $6.0 million associated with deferment fees relating to rigs that have yet to be delivered. Approximately $76.5 million was recorded to *"Rig contract termination costs"* 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 six months ended June 30, 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).

Interest expense and other decreased $2.3 million for the six months ended June 30, 2013, compared to the same period in 2012. The decrease 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 six months ended June 30, 2013, we recorded approximately $78.7 million of interest expense on the financing obligations compared to $80.5 million in the prior year.

We had an income tax benefit of $20.7 million for the six months ended June 30, 2013. This benefit is due to a combination of a change in state income tax rate in 2013 and our loss from continuing operations before income taxes of $15.7 million compared to an income tax benefit of $54.7 million due to our loss from continuing operations before income taxes of $156.5 million in the prior year. The effective tax rate for the six months ended June 30, 2013, was 131.7% compared to 35.0% for the six months ended June 30, 2012. The increase in our effective tax rate in the current year is primarily due to state income tax rate adjustments in relation to a reduced loss from continuing operations before income taxes during the transition period. Deferred tax assets and liabilities have been revalued as a result of reduction in apportionment of income in Louisiana from 43% to 39% in 2012 and resulting reduction of effective tax rate.

Investment in EagleHawk

EagleHawk had gross revenues of $51.8 million related to its Eagle Ford Shale gathering and treating systems in the Hawkville and Black Hawk Fields for the six months ended June 30, 2013, compared to $43.9 million for the six months ended June 30, 2012. Gross revenues include $28.5 million and $18.8 million of intercompany revenues that were eliminated in consolidation for the six months ended June 30, 2013 and 2012, respectively. Total operating expenses for EagleHawk for the six months ended June 30, 2013, of $43.9 million included $27.3 million in gathering, transportation and other expenses and $12.4 million in depreciation expense. Total operating expenses for the six months ended June 30, 2012, of $21.8 million included $11.4 million in gathering, transportation and other expenses and $7.6 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)

	Six Months Ended June 30, 2013	Years Ended December 31, 2012	2011	2010
Operating revenues:				
Oil and natural gas	$ 1,368,117	$ 2,023,561	$ 1,779,738	$ 1,107,401
Marketing	99,504	7,384	296,006	475,030
Midstream	30,563	75,897	23,648	18,216
Total operating revenues	1,498,184	2,106,842	2,099,392	1,600,647
Operating expenses:				
Marketing	99,635	6,884	322,232	521,378
Production:				
Lease operating	83,019	88,848	62,295	64,744
Workover and other	16,176	14,283	17,853	18,119
Taxes other than income	60,865	75,293	63,617	9,543
Gathering, transportation and other	224,027	316,200	175,494	99,375
General and administrative	108,320	180,079	282,167	155,493
Depletion, depreciation and amortization:	632,182	1,173,455	859,724	465,970
Rig contract termination costs	76,528	—	—	—
Impairment of intangible asset	—	67,237	—	—
Impairment of capitalized software costs	—	1,351	—	—
Total operating expenses	1,300,752	1,923,630	1,783,382	1,334,622
Income (loss) from operations	197,432	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	(213,112)	(433,046)	(403,952)	(336,307)
Total other income (expenses)	(213,112)	(461,306)	(40,238)	(35,186)
Income (loss) from continuing operations before income taxes	(15,680)	(278,094)	275,772	230,839
Income tax benefit (provision)	20,656	103,662	(98,545)	(94,934)
Income (loss) from continuing operations, net of income taxes	4,976	(174,432)	177,227	135,905
Loss from discontinued operations, net of income taxes	—	—	(3,079)	(45,984)
Net income (loss)	$ 4,976	$ (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)

	June 30,	December 31,	
	2013	**2012**	**2011**
Current assets:			
Cash	$ 214,990	$ 96,122	$ 174,436
Accounts receivable	523,257	584,442	410,115
Receivables from derivative contracts	—	—	371,584
Deferred income tax	9,950	16,046	—
Prepaid and other	33,372	29,798	42,060
Total current assets	781,569	726,408	998,195
Oil and natural gas properties (full cost method):			
Evaluated	15,329,505	13,213,484	10,509,954
Unevaluated	3,010,761	2,839,950	2,502,435
Gross oil and natural gas properties	18,340,266	16,053,434	13,012,389
Less – accumulated depletion	(7,297,291)	(6,708,875)	(5,598,420)
Net oil and natural gas properties	11,042,975	9,344,559	7,413,969
Other operating property and equipment:			
Gas gathering systems and equipment	1,648,198	1,348,822	918,810
Other operating assets	138,027	130,026	108,077
Gross other operating property and equipment	1,786,225	1,478,848	1,026,887
Less – accumulated depreciation	(168,367)	(126,366)	(61,363)
Net other operating property and equipment	1,617,858	1,352,482	965,524
Other noncurrent assets:			
Goodwill	932,802	932,802	932,802
Other intangible assets, net of amortization	—	—	78,289
Debt issuance costs, net of amortization	31,463	36,090	45,528
Deferred income taxes	351,506	352,446	326,878
Receivables from derivative contracts	—	—	5,147
Restricted cash	35,236	27,647	34,736
Other	13,676	14,792	11,859
Total assets	$ 14,807,085	$ 12,787,226	$ 10,812,927
Current liabilities:			
Accounts payable and accrued liabilities	$ 1,558,815	$ 1,166,106	$ 963,701
Deferred income taxes	—	—	79,748
Liabilities from derivative contracts	—	—	40,673
Payable on financing arrangements	20,894	19,467	17,631
Current portion of long-term debt	—	—	17,520
Total current liabilities	1,579,709	1,185,573	1,119,273
Long-term debt	3,206,766	3,201,761	3,192,641
Other noncurrent liabilities:			
Asset retirement obligations	156,083	57,236	52,317
Payable on financing arrangements	1,871,584	1,853,343	1,799,881
Other	415	417	640
Commitments and contingencies (Note 7)			
Stockholder's equity:			
Common stock: 100 shares of $.001 par value authorized, issued and outstanding at June 30, 2013, and December 31, 2012 and 2011	—	—	—
Additional paid-in capital	9,174,208	7,675,552	5,660,399
Accumulated deficit	(1,181,680)	(1,186,656)	(1,012,224)
Total stockholder's equity	7,992,528	6,488,896	4,648,175
Total liabilities and stockholder's equity	$ 14,807,085	$ 12,787,226	$ 10,812,927

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

PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY

(In thousands)

	Common Shares	Common Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholder's 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
Contribution from parent (2)	—	—	1,498,656	—	1,498,656
Net income	—	—	—	4,976	4,976
Balance at June 30, 2013	**—**	**—**	**$ 9,174,208**	**$ (1,181,680)**	**$ 7,992,528**

(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 from and non-cash contribution activity with BHP Billiton Limited. The cash funding for the six months ended June 30, 2013 and the year ended December 31, 2012 totals approximately $1.5 billion and $2.0 billion, respectively. The non-cash contributions for the six months ended June 30, 2013 and the year ended December 31, 2012 totals approximately $2.3 million and $21.2 million, respectively. The remaining $8.7 million decrease during the six months ended June 30, 2013, relates to cash settlement with BHP Billiton Limited of payroll related items previously considered non-cash contributions.

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

PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Six Months Ended June 30, 2013	Years Ended December 31, 2012	2011	2010
Cash flows from operating activities:				
Net income (loss)	$ 4,976	$ (174,432)	$ 174,148	$ 89,921
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depletion, depreciation and amortization	632,182	1,173,455	858,377	470,172
Impairment of capitalized software costs	—	1,351	—	—
Income tax provision (benefit)	(20,656)	(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	13,617	46,196	53,781	45,381
Change in assets and liabilities:				
Accounts receivable	61,187	(174,327)	(121,933)	(183,708)
Payable to KinderHawk Field Services LLC	—	—	(976)	976
Prepaid and other	(3,003)	13,102	25,643	(30,523)
Accounts payable and accrued liabilities	154,486	100,221	26,388	(41,424)
Other	3,796	191	(4,622)	14,393
Net cash provided by operating activities	846,585	1,267,870	1,074,522	505,627
Cash flows from investing activities:				
Oil and natural gas capital expenditures	(2,037,258)	(2,946,239)	(2,950,164)	(2,424,292)
Proceeds received from sale of oil and natural gas properties	2,391	—	86,438	1,178,937
Proceeds received from sale of Fayetteville gathering systems	—	—	76,898	—
Acquisition of CEU Hawkville LLC, net of cash acquired	—	—	(92,974)	—
Marketable securities purchased	—	—	(896,006)	(1,122,016)
Marketable securities redeemed	—	—	896,006	1,122,016
Increase in restricted cash	(180,275)	(380,088)	(348,971)	(198,210)
Decrease in restricted cash	172,686	387,177	314,235	411,914
Other operating property and equipment capital expenditures	(205,940)	(439,762)	(346,712)	(282,352)
Net cash used in investing activities	(2,248,396)	(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
Cash Contribution from parent	1,505,000	1,993,999	1,258,375	—
Restricted stock awards settled	—	—	(85,904)	—
Stock option awards and stock option appreciation rights	—	—	(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	31,250	72,279	886,119	917,437
Decrease in payable on financing arrangements	(15,571)	(33,550)	(13,532)	—
Debt issuance costs	—	—	(25,983)	(20,738)
Other	—	—	(4,415)	(3,768)
Net cash provided by financing activities	1,520,679	2,032,728	2,359,573	808,456
Net increase (decrease) in cash	118,868	(78,314)	172,845	80
Cash at beginning of period	96,122	174,436	1,591	1,511
Cash at end of period	$ 214,990	$ 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 oil and gas shale 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.

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 resulting transition period from January 1, 2013 through June 30, 2013 in this Transition Report is referred to as the six months ended June 30, 2013. The following table provides comparative statements of operations for the six months ended June 30, 2013 and the six months ended June 30, 2012.

	Six Months Ended June 30,	
	2013	**2012**
Operating revenues:		
Oil and natural gas	$ 1,368,117	$ 965,274
Marketing	99,504	(67)
Midstream	30,563	40,778
Total operating revenues	1,498,184	1,005,985
Operating expenses:		
Marketing	99,635	—
Production:		
Lease operating	83,019	44,291
Workover and other	16,176	8,243
Taxes other than income	60,865	29,880
Gathering, transportation and other	224,027	157,750
General and administrative	108,320	99,245
Depletion, depreciation and amortization	632,182	578,064
Rig reduction costs	76,528	—
Impairment of capitalized software costs	—	1,351
Total operating expenses	1,300,752	918,824
Income (loss) from operations	197,432	87,161
Other income (expenses):		
Net gain (loss) on derivative contracts	—	(28,260)
Interest expense and other	(213,112)	(215,413)
Total other income (expenses)	(213,112)	(243,673)
Income (loss) from continuing operations before income taxes	(15,680)	(156,512)
Income tax benefit (provision)	20,656	54,738
Net income (loss)	$ 4,976	$ (101,774)

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 June 30, 2013, and at December 31, 2012 and 2011, was approximately $2.6 million, $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 six months ended June 30, 2013 and for the year ended December 31, 2012. The Company 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 BHP Billiton Petroleum (Eagle Ford Gathering) LLC, formally known as 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 June 30, 2013, and December 31, 2012 and 2011 consisted of the following:

	June 30, 2013	December 31, 2012	December 31, 2011
		(In thousands)	
Gas gathering systems and equipment	$ 1,648,198	$ 1,348,822	$ 918,810
Less – accumulated depreciation	(88,714)	(66,461)	(33,162)
Net gas gathering systems and equipment	$ 1,559,484	$ 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 June 30, 2013, and December 31, 2012 and 2011, the table above includes approximately $398.1 million, $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 June 30, 2013, and December 31, 2012 and 2011, the table above includes approximately $909.4 million, $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 June 30, 2013, and December 31, 2012 and 2011, was approximately $1.9 billion, $1.9 billion, and $1.8 billion, respectively, of which approximately $20.9 million, $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 $30.4 million, $23.5 million, and $34.7 million as *"Restricted cash"* at June 30, 2013, and 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 $4.8 million and $4.1 million as *"Restricted Cash"* at June 30, 2013 and 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, and 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. However, the Company may engage, from time to time, in marketing operations when this meets the needs of the business.

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 do 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. During the first six months of 2013, one 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 37% of the Company's total sales. 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 2008 through 2012 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.

In order to align with the new fiscal year, the Company elected to perform its goodwill test annually during the quarter ending June 30 or more often if circumstances require; previously, the Company performed its goodwill test annually during the quarter ending September 30. During the quarter ended June 30, 2013, 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 were 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 fiscal year 2013. 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 quarter ended June 30, 2013 and the quarters ended September 30, 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.

There was no amortization expense for the six months ended June 30, 2013. 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 has been 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 June 30, 2013, and December 31, 2012 and 2011 are as follows:

	June 30,	December 31,	
	2013	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

Subsequent to December 31, 2012, all Petrohawk 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. BHP

Billiton Limited matches employee contributions dollar-for-dollar on the first 6% of an employee's earnings. This applies to either tax deferred contributions or post tax contributions up to a maximum of 6%. For the six months ended June 30, 2013, the Company charged to expense plan contributions of $3.5 million.

Prior to 2013, the Company sponsored a 401(k) tax deferred savings plan, whereby the Company matched a portion of employees' contributions in cash. Participation in the plan was 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 matched employee contributions dollar-for-dollar on the first 10% of an employee's pretax earnings.

Recently Issued Accounting Pronouncements

In February 2013, the FASB issued ASU 2013-04, *Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date* (ASU 2013-04). This guidance is intended to provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, excluding obligations accounted for under existing guidance. This guidance requires an entity to measure these obligations as a sum of the amount the reporting entity agreed to pay and any additional amount the reporting entity expects to pay on behalf of its co-obligors. This guidance will be effective for fiscal years ending after December 15, 2014, and interim and annual periods thereafter, with early adoption permitted. The Company is currently assessing the impact, if any, that ASU 2013-04 will have on its 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 BHP Billiton Petroleum (TX Gathering), LLC, formally known as 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 $241.0 million as of June 30, 2013, 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 six months ended June 30, 2013, and for all prior periods, 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 June 30, 2013, 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 June 30, 2013, and December 31, 2012 and 2011, consisted of the following:

	June 30,	December 31,	
	2013	2012	2011
		(In thousands)	
Subject to depletion	$ 15,329,505	$ 13,213,484	$ 10,509,954
Not subject to depletion:			
Exploration and extension wells in progress	661,357	399,672	75,635
Other capital costs:			
Incurred in 2013	45,530	—	—
Incurred in 2012	176,802	169,782	—
Incurred in 2011	678,070	697,854	728,987
Incurred in 2010	338,972	379,796	421,759
Incurred in 2009	284,405	301,101	319,656
Incurred in 2008 and prior	825,625	891,745	956,398
Total not subject to depletion	3,010,761	2,839,950	2,502,435
Gross oil and natural gas properties	18,340,266	16,053,434	13,012,389
Less accumulated depletion	(7,297,291)	(6,708,875)	(5,598,420)
Net oil and natural gas properties	$ 11,042,975	$ 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. 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 June 30, 2013, the ceiling test value of the Company's reserves was calculated based on the first day average of the 12-months ended June 30, 2013, of the West Texas Intermediate (WTI) spot price of $91.60 per barrel or was calculated based equally on the respective first day average of the 12-months ended June 30, 2013, of the WTI spot price of $91.60 per barrel and the Light Louisiana Sweet (LLS) differential spot price of $16.95 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 June 30, 2013 of the Henry Hub price of $3.47 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 June 30, 2013 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, 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) differential spot price of $16.90 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.

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 June 30, 2013, and December 31, 2012 and 2011 consisted of the following:

	June 30,	**December 31,**	
	2013	**2012**	**2011** [(1)]
		(In thousands)	
6.25% $600 million senior notes [(2)]	$ 600,000	$ 600,000	$ 600,000
7.25% $1.2 billion senior notes [(3)]	1,230,501	1,230,942	1,231,780
10.5% $600 million senior notes [(4)]	576,654	571,208	561,250
7.875% $800 million senior notes	799,611	799,611	799,611
	$ 3,206,766	$ 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 $5.5 million, $5.9 million, and $6.8 million premium at June 30, 2013, and 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 a $13.0 million, $18.4 million, and $28.4 million discount, at June 30, 2013, and 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 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 2018 Indenture) occurred that resulted in certain covenants in the 2018 Indenture, including covenants relating to incurrence of indebtedness, restricted payments, asset sales and affiliate transactions, being terminated.

In conjunction with the issuance of the additional 2018 Notes, the Company recorded a premium of $7.5 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized premium was $5.5 million, $5.9 million, and $6.8 million at June 30, 2013, and December 31, 2012 and 2011, respectively.

10.5% Senior Notes

On January 27, 2009, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million of its 10.5% senior notes due August 1, 2014 (the 2014 Notes). The 2014 notes were issued under and are governed by an indenture dated January 27, 2009, between the Company, U.S. Bank Trust National Association, as trustee, and the Company's subsidiaries named therein as guarantors (the 2014 Indenture). The 2014 Notes were priced at 91.279% of the face value to yield 12.7% to maturity. Net proceeds from the offering were used to repay all outstanding borrowings on the Company's Senior Credit Agreement.

The 2014 Notes bear interest at a rate of 10.5% per annum, payable semi-annually on February 1 and August 1 of each year, commencing August 1, 2009. The 2014 notes will mature on August 1, 2014. The 2014 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2014 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 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

The Company may redeem some or all of the 2014 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 February 1 of the years indicated below:

Year	Percentage
2013	105.250
2014	100.000

The Company is required to offer to repurchase the 2014 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 2014 Indenture. The 2014 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. On September 16, 2011, the Company initiated an offer to repurchase the 2014 Notes, in accordance with the terms of the 2014 Indenture, due to the change of control resulting from the acquisition of the Company by BHP Billiton Limited. The holders of the 2014 Notes had until November 9, 2011 to tender their 2014 Notes. On November 14, 2011, the Company paid principal and interest of $10.8 million to repurchase a portion of the 2014 Notes at the request of the bondholders. The 2014 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2014 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 2014 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

In conjunction with the issuance of the 2014 Notes, the Company recorded a discount of $52.3 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $13.0 million, $18.4 million, and $28.4 million at June 30, 2013, and December 31, 2012 and 2011, respectively.

7.875% Senior Notes

On May 13, 2008 and June 19, 2008, the Company issued $500 million principal amount and $300 million principal amount, respectively, of its 7.875% senior notes due 2015 (the 2015 Notes) pursuant to an indenture (the 2015 Indenture). The 2015 Notes were issued under and are governed by an indenture dated May 13, 2008, between the Company, U.S. Bank Trust National Association, as trustee, and the Company's subsidiaries named therein as guarantors.

The 2015 Notes bear interest at a rate of 7.875% per annum, payable semi-annually on June 1 and December 1 of each year, commencing December 1, 2008. The 2015 Notes will mature on June 1, 2015. The 2015 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2015 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 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

The Company may redeem up to 35% of the aggregate principal amount of the 2015 Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.875% of the principal amount plus accrued interest and unpaid interest to the redemption date provided that: at least 65% in aggregate principal amount of the 2015 Notes originally issued under the 2015 Indenture remain outstanding immediately after the redemption.

The Company may redeem some or all of the 2015 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 June 1 of the years indicated below:

Year	Percentage
2013	101.969
2014	100.000

The Company is required to offer to repurchase the 2015 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 2015 Indenture. The 2015 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. On September 16, 2011, the Company initiated an offer to repurchase the 2015 Notes, in accordance with the terms of the 2015 Indenture, due to the change of control resulting from the acquisition of the Company by BHP Billiton Limited. The holders of the 2015 Notes had until November 9, 2011 to tender their 2015 Notes. On November 14, 2011, the Company paid principal and interest of $0.4 million to repurchase a portion of the 2015 Notes at the request of the bondholders. The 2015 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2015 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 2015 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

7.125% Senior Notes

On July 12, 2006, the date of the Company's merger with KCS Energy, Inc. (KCS), the Company assumed (pursuant to the Second Supplemental Indenture relating to the 7.125% senior notes, also referred to as the 2012 Notes), and subsidiaries of the Company guaranteed (pursuant to the Third Supplemental Indenture relating to such notes), all the obligations (approximately $275 million) of KCS under the 2012 Notes and the Indenture dated April 1, 2004 (the 2012 Indenture) among KCS, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, which governs the terms of the 2012 Notes. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1. The 2012 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 2012 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

In conjunction with the assumption of the 7.125% senior notes from KCS, the Company recorded a discount of $13.6 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The Company had no remaining unamortized discount at December 31, 2011, and $3.5 million at December 31, 2010.

On March 17, 2011, the Company redeemed all of the outstanding 2012 Notes with a portion of the proceeds received from the issuance of the additional 2018 Notes.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130 million of its 9.875% senior notes due 2011 (the 2011 Notes). The Company assumed these notes upon the closing of the Company's merger with Mission. In conjunction with the Company's merger with KCS, the Company repurchased substantially all of the 2011 Notes. In connection with the extinguishment of substantially all of the 2011 Notes, the Company requested and received from the noteholders consent to eliminate the debt covenants associated with the 2011 Notes. There were approximately $0.2 million of the notes that were not redeemed and were still outstanding and classified as current as of December 31, 2010. On April 1, 2011, the Company repaid the $0.2 million of the 2011 Notes that were outstanding.

Debt Maturities

Aggregate maturities required on long-term debt at June 30, 2013 are due in future fiscal years as follows (in thousands):

2014	$ —
2015	1,389,251
2016	—
2017	—
2018	—
Thereafter	1,825,000
Total	$ 3,214,251

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt. The Company expensed approximately $4.6 million in debt issuance costs during the six months ended June 30, 2013, which includes amortization of capitalized costs, on the consolidated statement of operations in *"Interest expense and other"*. The Company expensed approximately $9.4 million in debt issuance costs during 2012, which includes both amortization and write downs in capitalized costs, on the consolidated statement of operations in *"Interest expense and other"*. In the quarter ended March 31, 2012, the Company wrote off $0.2 million of debt issuance costs in conjunction with the termination of the Company's Senior Credit Agreement. During the year ended December 31, 2011, the Company capitalized $26.0 million in debt issuance costs associated with the issuances of the additional 2018 Notes and the 2019 Notes, the Company's EagleHawk Revolving Credit Agreement, as well as costs incurred for amendments to the Company's Senior Credit Agreement. The Company expensed approximately $26.4 million in debt issuance costs during 2011, which includes both amortization and write downs in capitalized costs. In the quarter ended March 31, 2011, the Company wrote off $0.2 million of debt issuance costs as a result of the additional 2018 Notes issuance and the corresponding reduction to the borrowing base of the Company's Senior Credit Agreement. In the quarter ended September 30, 2011, the Company wrote off $0.8 million of debt issuance costs as a result of the removal of the midstream component of the borrowing base in the Company's Senior Credit Agreement. In the quarter ended December 31, 2011, the Company wrote off $0.1 million of debt issuance costs due to the repurchase of a portion of the 2014 and 2015 Notes, approximately $0.4 million due to the termination of the EagleHawk Revolving Credit Agreement, and approximately $13.8 million due to the reduction of the Company's availability under the Senior Credit Agreement. At June 30, 2013, and December 31, 2012 and 2011, the Company had approximately $31.5 million, $36.1 million, and $45.5 million, respectively, of debt issuance costs remaining that are being amortized over the lives of the respective debt.

5. FAIR VALUE MEASUREMENTS

Pursuant to ASC 820, *Fair Value Measurements and Disclosures* (ASC 820) the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of December 31, 2011. There were no financial assets or liabilities that were accounted for at fair value as of June 30, 2013 and December 31, 2012, as the Company terminated its existing derivative contracts during the first quarter of 2012. See further discussion of the termination of the Company's derivative contracts in Note 8, *"Derivatives."* As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for the years ended December 31, 2012 and 2011.

	December 31, 2011			
	Level 1	**Level 2**	**Level 3**	**Total**
		(In thousands)		
Assets:				
Receivables from derivative contracts	$ —	$ 376,731	$ —	$ 376,731
Liabilities:				
Liabilities from derivative contracts	$ —	$ 40,673	$ —	$ 40,673

Derivatives listed above include collars, swaps, and put options that are carried at fair value. The Company records the net change in the fair value of these positions in *"Net gain on derivative contracts"* in the Company's consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curve for commodity prices based on quoted markets prices and implied volatility factors related to changes in the forward curves.

As of December 31, 2011, the Company's derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance. Each of the counterparties to the Company's derivative contracts was a lender in the Company's Senior Credit Agreement. The Company did not post collateral under any of these contracts as they were secured under the Senior Credit Agreement.

As discussed in Note 2, *"Acquisitions and Divestitures,"* the Company acquired additional interests primarily in the Hawkville Field of the Eagle Ford Shale from CEU Hawkville, LLC on December 22, 2011, for $90 million before customary closing adjustments. The Company recorded the estimated 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 in accordance with ASC 805.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. The estimated fair value amounts have been determined at discrete points in time based on relevant market information, categorizing these as Level 2 within the fair value hierarchy in accordance with ASC 820. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The following table presents the estimated fair values of the Company's fixed interest rate, long-term debt instruments as of June 30, 2013, and December 31, 2012 and 2011 (excluding premiums and discounts and deferred premiums on derivative contracts):

	June 30, 2013		**December 31, 2012**		**December 31, 2011**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Debt			**(in thousands)**			
6.25% $600 million senior notes	$ 600,000	$ 657,948	$ 600,000	$ 684,600	$ 600,000	$ 661,500
7.25% $1.2 billion senior notes	1,225,000	1,306,463	1,225,000	1,375,063	1,225,000	1,398,668
10.5% $600 million senior notes	589,640	631,200	589,640	635,250	589,640	659,660
7.875% $800 million senior notes	799,611	816,720	799,611	832,800	799,611	853,585
	$ 3,214,251	$ 3,412,331	$ 3,214,251	$ 3,527,713	$ 3,214,251	$ 3,573,413

The fair values of the Company's fixed interest debt instruments were calculated using quoted market prices based on trades of such debt as of June 30, 2013, and December 31, 2012 and 2011, respectively.

6. ASSET RETIREMENT OBLIGATION

The Company records an asset retirement obligation (ARO) when the total depth of a drilled well is reached and the Company can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. For gas gathering systems and equipment, the Company records an ARO when the system is placed in service and the Company can reasonably estimate the fair value of an obligation to perform site reclamation and other necessary work. The Company records the ARO liability on the consolidated balance sheets and capitalizes a portion of the cost in *"Oil and natural gas properties"* or "*Gas gathering systems and equipment*" during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *"Depletion, depreciation and amortization"* expense in the consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis or straight-line basis.

The Company recorded the following activity related to the ARO liability for the six months ended June 30, 2013, and the years ended December 31, 2012 and 2011 (in thousands):

Liability for asset retirement obligation as of December 31, 2010	$ 31,741
Liabilities settled and divested [(1)]	(734)
Additions	18,834
Acquisitions [(1)]	350
Accretion expense	2,126
Liability for asset retirement obligation as of December 31, 2011	52,317
Additions	14,585
Accretion expense	2,626
Revisions in estimated cash flows and other	(12,292)
Liability for asset retirement obligation as of December 31, 2012	57,236
Additions	104,127
Accretion expense	2,618
Revisions in estimated cash flows and other	(7,898)
Liability for asset retirement obligation as of June 30, 2013	$ 156,083

(1) Refer to Note 2 *"Acquisitions and Divestitures"* for more details on the Company's divestiture activities.

7. COMMITMENTS AND CONTINGENCIES

Commitments

The Company leases corporate office space in Houston, Texas and Tulsa, Oklahoma as well as a number of other field office locations. In addition, the Company has lease commitments related to certain vehicles, machinery and equipment under long-term operating leases. Rent expense was $8.9 million, $13.3 million, $8.3 million and $6.4 million for the six months ended June 30, 2013, and the years ended December 31, 2012, 2011 and 2010, respectively.

As of June 30, 2013, the Company had the following commitments:

	Total Commitment Amount	Years Remaining
	(in thousands)	
Gathering and transportation commitments	$ 3,419,304	16
Drilling rig commitments	692,969	6
Pipeline and well equipment obligations	135,726	1
Non-cancelable operating leases	18,108	4
Various contractual commitments (including, among other things, rental equipment obligations, obtaining and processing seismic data)	31,992	1
Total commitments	$ 4,298,099	

Subsequent to June 30, 2013, the Company elected to modify the number of rigs within the rig fleet. As such, the Company incurred costs of approximately $60 million during September 2013 related to the cancellation of rig contracts.

As part of the KinderHawk transaction, one of the Company's gathering and transportation commitments is the obligation to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from the Company's operated wells producing from the Haynesville and Lower Bossier Shales, within 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. This minimum annual quantities commitment is not included in the table above. The Company's obligation to deliver minimum annual quantities of natural gas to KinderHawk through May 2015 remains in effect following the transfer of the Company's remaining 50% membership interest in KinderHawk on July 1, 2011. The minimum annual quantities per contract year are as follows:

Contract Year	Minimum Annual Quantity (Bcf)
Year 1 (partial)—2010	81.090
Year 2—2011	152.899
Year 3—2012	238.595
Year 4—2013	324.047
Year 5—2014	368.614
Year 6 (partial)—2015	143.066

These volumes represent 50% of the Company's anticipated production from the specified acreage at the time the Company entered into the contract.

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 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. In the event that annual natural gas deliveries are ever less than the minimum annual quantity per contract year set forth in the table above, the Company's fee obligation would be determined by subtracting the quantity delivered from the minimum annual quantity for the applicable contract year and multiplying the positive difference by the sum of the gathering fee in effect on the last day of such year plus the average monthly treating fees for such year. For example, if the quantity of natural gas delivered in 2013 were 50 Bcf less than the minimum annual quantity for such year and the year-end gathering fee was $0.34 per Mcf and the average treating fee for the period was $0.345 per Mcf, the fee would be $34.3 million. No such fee has been paid to date.

As previously discussed, the Company has certain amounts associated with the sale of its interests in KinderHawk and EagleHawk recorded as financing obligations in the consolidated balance sheets, which are not reflected in the amounts shown in the table above. The balance of the Company's financing obligations as of June 30, 2013, and December 31, 2012 and 2011, was approximately $1.9 billion, $1.9 billion, and $1.8 billion, respectively, of which approximately $20.9 million, $19.5 million, and $17.6 million was classified as current for the respective periods.

Contingencies

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. All known liabilities are accrued based on the Company's best estimate of the probable loss. While the outcome and impact of currently pending legal proceedings cannot be determined, the Company's management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company's consolidated operating results, financial position or cash flows.

8. DERIVATIVES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts were utilized to economically hedge the Company's exposure to price fluctuations and reduce the variability in the Company's cash flows associated with anticipated sales of future oil, natural gas and natural gas liquids production. Historically, the Company has generally hedged a substantial, but varying, portion of anticipated oil, natural gas and natural gas liquids production and may do so again at some point in the future. Derivatives are carried at fair value on the consolidated balance sheets, with the changes in the fair value included in the consolidated statements of operations for the period in which the change occurs.

It has been the Company's policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to the Company's derivative contracts was a lender in the Company's Senior Credit Agreement. The Company did not post collateral under any of these contracts as they were secured under the Company's Senior Credit Agreement.

On December 20, 2011, the Company entered into a Master Transaction Agreement (the MTA) with Barclays Bank PLC (Barclays) in order to facilitate the termination of a portion of its existing derivative positions. During the first quarter of 2012, the Company completed the transaction and all outstanding positions were terminated. As a result, Barclays paid the Company approximately $209 million. In addition, during the first quarter of 2012, the Company received $68.5 million for the termination of its outstanding derivative positions with BNP Paribas.

The Company did not elect to designate any of its historical derivative contracts for hedge accounting. Accordingly, the Company recorded the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *"Net gain (loss) on derivatives contracts"* on the consolidated statements of operations.

At June 30, 2013, and December 31, 2012, the Company had no open commodity derivative contracts.

At December 31, 2011, the Company had 63 open commodity derivative contracts summarized in the tables below: 38 natural gas collar arrangements, 11 natural gas swap arrangements and 14 crude oil collar arrangements. Derivative commodity contracts in 2012 through the date of termination and in 2011 settled based on NYMEX WTI and Henry Hub prices, which may have differed from the actual price received by the Company for the sale of its oil and natural gas production.

Additionally, as of December 31, 2011, the Company had deferred premiums on derivative contracts outstanding in the amount of approximately $17.5 million, which was included in the "*Current Portion of long-term debt*" on the consolidated balance sheets. These deferred premiums were settled during the first quarter of 2012.

All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the consolidated balance sheets as assets or liabilities. The following table summarizes the location and fair value amounts of all derivative contracts in the consolidated balance sheets as of December 31, 2011:

	Asset derivative contracts		Liability derivative contracts	
Derivatives not designated as hedging contracts under ASC 815	**Balance sheet location**	**December 31, 2011**	**Balance sheet location**	**December 31, 2011**
		(In thousands)		
Commodity contracts	Current assets – receivables from derivative contracts	$ 371,584	Current liabilities – liabilities from derivative contracts	$ (40,673)
Commodity contracts	Other noncurrent assets – receivables from derivative contracts	5,147	Other noncurrent liabilities – liabilities from derivative contracts	—
		$ 376,731		$ (40,673)

The following table summarizes the location and amount of the Company's realized and unrealized gains and losses on derivative contracts in the Company's consolidated statements of operations:

Derivative not designated as hedging contracts under ASC 815	**Location of gain or (loss) recognized in income on derivative contracts**	**Amount of gain or (loss) in income on derivative contracts year ended December31, 2012**	**2011**	**2010**
Commodity contracts:			**(in thousands)**	
Unrealized gain (loss) on commodity contracts	Other income (expense) – net gain on derivative contracts	$ (336,058)	$ 90,127	$ 58,075
Realized gain on commodity contracts	Other income (expense) – net gain on derivative contracts	307,798	273,587	243,046
Total net gain (loss) on commodity contracts		$ (28,260)	$ 363,714	$ 301,121

At December 31, 2011 the Company had the following open derivative contracts:

			December 31, 2011	Floors		Ceilings	
Period	**Instrument**	**Commodity**	**Volume in Mmbtu's/ Bbl's/Gal's**	**Price / Price Range**	**Weighted Average Price**	**Price / Price Range**	**Weighted Average Price**
January 2012 - December 2012	Collars	Natural gas	184,830,000	$4.75 - $5.00	$4.86	$5.70 - $8.00	$6.55
January 2012 - December 2012	Swaps	Natural gas	36,600,000	5.05 - 5.20	5.16		
January 2012 - December 2012	Collars	Crude oil	5,124,000	75.00 - 90.00	80.71	98.00 - 130.00	104.27
January 2013 - December 2013	Swaps	Natural gas	3,650,000	5.40	5.40		

9. STOCKHOLDER'S EQUITY

As discussed in Note 1, "*Summary of Significant Events and Accounting Policies,*" pursuant to the terms of the Merger Agreement on August 20, 2011, Purchaser accepted for payment all Shares of the Company's common stock, approximately 293.9 million shares, representing approximately 97.4% of the total outstanding shares and on August 25, 2011, Purchaser completed a short-form merger under Delaware law of Purchaser with and into the Company, with the Company being the surviving corporation. At the effective time of such merger, each share issued and outstanding immediately prior to the effective time of such merger ceased to be issued and outstanding and were converted into the right to receive an amount in cash equal to the Offer Price, without interest. As a result of such merger, the Company is authorized to issue 100 shares with par value of $0.001 per share all of which are owned by Parent.

For the six months ended June 30, 2013 and the year ended December 31, 2012, the Company recognized nothing, and for the year ended December 31, 2011, the Company recognized $53.2 million of non-cash stock-based compensation expense.

Incentive Plans

The Company's Incentive Plans included the Fourth Amended and Restated 2004 Employee Incentive Plan (2004 Employee Plan), Second Amended and Restated 2004 Non-Employee Director Incentive Plan (2004 Non-Employee Director Plan), 1999 Incentive and Non-Statutory Stock Option Plan, Mission Resources Corporation 1994 Stock Incentive Plan (Mission 1994 Plan), Mission Resources Corporation 1996 Stock Incentive Plan (Mission 1996 Plan) and Mission Resources Corporation 2004 Incentive Plan (Mission 2004 Plan), KCS Energy, Inc. 2001 Employee and Directors Stock Plan (KCS 2001 Plan) and the KCS Energy, Inc. 2005 Employee and Directors Stock Plan (KCS 2005 Plan). As discussed above, the Company completed the BHP Merger on August 25, 2011 and the aforementioned plans were terminated thereafter.

Stock Options and Stock Appreciation Rights

Certain of the Company's incentive plans permitted awards of stock appreciation rights (SARS) and stock options. A stock appreciation right is similar to a stock option, in that it represents the right to realize the increase in market price, if any, of a fixed number of shares over the grant value of the right, which is equal to the market price of the Company's common stock on the date of grant. Stock options, when exercised, are settled through the payment of the exercise price in exchange for shares of stock underlying the option. SARS, when exercised, are settled without cash in exchange for a net of tax number of shares of common stock valued on the date of settlement. Both SARS and stock options vest one-third annually after the original grant date and have a term of ten years from the date of grant.

The Company did not grant any options in 2013 or 2012. The weighted average grant date fair value of options granted in 2011 was $24.7 million. These awards vest over a three year period at a rate of one-third on the annual anniversary date of the grant, subject to acceleration in the event of a change of control of the Company, and expire ten years from the grant date. In conjunction with the BHP Merger, the Company cancelled all of its unexercised stock options and stock appreciation rights, including vested and unvested, and distributed the excess of $38.75 over the exercise price per unit to each holder, net of applicable withholding taxes. As a result, all of the Company's remaining unrecognized compensation expense of $25.2 million was accelerated and recognized as stock-based compensation expense. No stock options or stock appreciation rights remain outstanding as of June 30, 2013, or December 31, 2012 and 2011. There were 4,816 options which expired in 2011.

The following table sets forth the warrants, options and stock appreciation rights transactions for the years ended December 31, 2011:

	Number	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value (1) (In thousands)	Weighted Average Remaining Contractual Life (Years)
Outstanding at December 31, 2010	8,086,189	$ 14.58	$ 36,856	6.8
Granted	2,347,230	20.67		
Exercised	(442,779)	14.20		
Forfeited	(156,755)	20.83		
Cash settled	(9,833,885)	15.95		
Outstanding at December 31, 2011	—	$ —	$ —	—

(1) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of stock options exercised during the year ended December 31, 2010 was approximately $2.1 million.

Restricted Stock

From time to time, the Company granted shares of restricted stock to employees and non-employee directors of the Company. Employee shares vest over a three-year period at a rate of one-third on the annual anniversary date of the grant, subject to acceleration in the event of a change of control of the Company, and the non-employee directors' shares vest six-months from the date of grant. The Company did not issue any restricted stock in 2013 or 2012. The weighted average grant date fair value of the shares granted in 2011 was $27.2 million. In conjunction with the BHP Merger, the Company purchased and cancelled all of the outstanding unvested restricted stock from employees and non-employee directors of the Company, and distributed $38.75 per share to each holder, net of applicable withholding taxes. As a result, all of the Company's remaining unrecognized compensation expense of $27.3 million was accelerated and recognized as stock-based compensation expense. No restricted stock remains outstanding as of June 30, 2013, or December 31, 2012 and 2011.

The following table sets forth the restricted stock transactions for the years ended December 31, 2011:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value (1) (In thousands)
Unvested outstanding shares at December 31, 2010	1,689,640	$ 19.54	$ 30,836
Granted	1,306,060	20.86	
Vested	(689,386)	20.98	
Forfeited	(89,419)	20.08	
Cash settled	(2,216,895)	20.45	
Unvested outstanding shares at December 31, 2011	—	$ —	$ —

(1) The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2010 of the underlying stock multiplied by the number of restricted shares.

Assumptions

The assumptions used in calculating the fair value of the Company's stock-based compensation are disclosed in the following table (no options were granted in 2013 or 2012):

	Year Ended December 31, 2011
Weighted average value per option granted during the period	$ 10.52
Assumptions:	
Stock price volatility (1)	58.0%
Risk free rate of return	2.01%
Expected term	5.0 years

(1) In 2011, the Company used a combination of implied and historic volatility.

10. INCOME TAXES

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

	Six Months Ended June 30, 2013	Years Ended December 31, 2012	2011	2010
		(in thousands)		
Current:				
Federal	$ 28,329	$ (22,431)	$ (72,659)	$ (106,831)
State	—	3,054	(771)	530
	28,329	(19,377)	(73,430)	(106,301)
Deferred:				
Federal	(29,036)	113,944	(21,060)	26,759
State	21,363	9,095	(4,055)	(15,392)
	(7,673)	123,039	(25,115)	11,367
Total income tax (provision) benefit	$ 20,656	$ 103,662	$ (98,545)	$ (94,934)

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

	Six Months Ended June 30, 2013 [(1)]	Years Ended December 31, 2012	2011	2010 [(2)]
		(in thousands)		
Expected tax (provision) benefit	$ 5,490	$ 97,333	$ (96,520)	$ (80,795)
State income taxes, net	317	6,589	(7,165)	(13,696)
Change in state income tax rate	14,176	1,280	4,453	2,631
Other	673	(1,540)	687	(3,074)
Total income tax (provision) benefit	$ 20,656	$ 103,662	$ (98,545)	$ (94,934)

(1) *"Change in state income tax rate"* in 2013 of $14.2 million is due to estimated allocation of income amongst various states in which the company has operations versus actual tax return filings. Deferred tax assets and liabilities have been revalued as a result of reduction in apportionment of income in Louisiana from 43% to 39% in 2012 and resulting reduction of effective tax rate.

(2) *"State income taxes, net"* in 2010 include a $6.6 million valuation allowance attributed to the sale of Fayetteville Shale assets.

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

	June 30, 2013	December 31, 2012	December 31, 2011
		(in thousands)	
Deferred current income tax assets (liabilities):			
Unrealized hedging transactions	$ —	$ —	$ (87,543)
Payable on financing arrangement	7,734	7,280	6,629
Bonus accrual	1,246	7,055	—
Other	970	1,711	1,166
Deferred current income tax assets (liabilities)	$ 9,950	$ 16,046	$ (79,748)
Deferred noncurrent income tax assets:			
Net operating loss carry-forwards	$ 2,111,654	$ 1,417,834	$ 759,100
Payable on financing arrangement	692,825	693,134	676,725
Alternative minimum tax credit carryforwards	181,463	210,054	187,622
Asset retirement obligations	57,779	21,404	19,670
Investment in partnership	81,404	85,375	64,130
Other	1,383	3,823	2,877
Gross deferred noncurrent income tax assets	3,126,508	2,431,624	1,710,124
Valuation allowance	(8,403)	(8,309)	(8,309)
Deferred noncurrent income tax assets	$ 3,118,105	$ 2,423,315	$ 1,701,815
Deferred noncurrent income tax liabilities:			
Book-tax differences in property basis	$ (2,766,599)	$ (2,070,869)	$ (1,373,861)
Unrealized hedging transactions	—	—	(1,076)
Deferred noncurrent income tax liabilities	$ (2,766,599)	$ (2,070,869)	$ (1,374,937)
Net noncurrent deferred income tax assets	$ 351,506	$ 352,446	$ 326,878

ASC 740 prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. There was not a material impact on the Company's operating results, financial position or cash flows as a result of the adoption of the provisions of ASC 740. During the second quarter of 2013, the Company determined that unrecognized tax positions should now be recognized. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows (in thousands):

Balance at January 1, 2011	$ 3,483
Additions for income tax positions of prior years	1,400
Reductions for income tax positions of prior years	(303)
Lapse of statute of limitations	(410)
Balance at December 31, 2011	4,170
Additions for income tax positions of prior years	3,222
Reductions for income tax positions of prior years	(791)
Lapse of statute of limitations	—
Balance at December 31, 2012	$ 6,601
Additions for income tax positions of prior years	—
Reductions for income tax positions of prior years	(6,601)
Lapse of statute of limitations	—
Balance at June 30, 2013	$ —

The Company previously accrued $0.4 million as of December 31, 2012, and $0.1 million as of December 31, 2011 and 2010 for penalties and interest on its unrecognized income tax benefits. The Company recognized changes in its accruals in "*Interest expense and other*" in its statements of operations. As a result of recognizing previously unrecognized tax positions, total previously recorded interest and penalties of $0.7 million was reversed during the second quarter of 2013.

As of June 30, 2013, the Company had available, to reduce future taxable income, a United States federal regular net operating loss (NOL) carryforward of approximately $5.6 billion (net of excess income tax benefits not recognized of $236.3 million), which expire in the years 2016 through 2031. Utilization of NOL carryforwards is subject to annual limitations due to stock ownership changes. The income tax net operating loss carryforward may be limited by other factors as well. The Company also has various state NOL carryforwards, reduced by the valuation allowance for losses that the Company anticipates will expire before they can be utilized, totaling approximately $5.2 billion, (net of Texas credit for business loss carryforwards) at June 30, 2013, with varying lengths of allowable carryforward periods ranging from five to 20 years that can be used to offset future state taxable income. It is expected that these deferred income tax benefits will be utilized prior to their expiration.

11. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	June 30,	December 31,	
	2013	2012	2011
		(in thousands)	
Accounts receivable:			
Oil and natural gas revenues	$ 248,631	$ 196,220	$ 196,662
Joint interest accounts	221,573	333,390	182,134
Income and other taxes receivable	12,055	19,008	20,795
Other	40,998	35,824	10,524
	$ 523,257	$ 584,442	$ 410,115
Prepaids and other:			
Prepaid insurance	$ 279	$ 3,320	$ 8,652
Prepaid drilling costs	29,323	23,349	29,013
Other	3,770	3,129	4,395
	$ 33,372	$ 29,798	$ 42,060
Accounts payable and accrued liabilities:			
Trade payables	$ 167,023	$ 48,322	$ 26,977
Revenues and royalties payable	214,517	220,737	126,897
Accrued oil and natural gas capital costs	726,179	559,714	465,299
Accrued midstream capital costs	125,558	45,445	42,620
Accrued interest expense	67,721	68,312	67,937
Prepayment liabilities	7,820	57,762	49,657
Payable to parent	31,510	—	—
Accrued lease operating expenses	16,388	15,035	10,902
Accrued ad valorem taxes payable	16,733	19,574	18,972
Accrued production taxes payable	11,272	9,220	3,411
Accrued gathering, transportation and other expenses	72,534	50,712	55,513
Accrued employee compensation	3,365	18,880	40,682
Income taxes payable	(1,485)	23,806	2,317
Other	99,680	28,587	52,517
	$ 1,558,815	$1,166,106	$ 963,701

Certain cash and non-cash related items are comprised of the following:

	Six Months Ended June 30, 2013	Years Ended December 31, 2012	2011	2010
Cash payments:				
Interest payments	$ 125,606	$ 251,217	$ 242,487	$ 276,716
Income tax payments, net	—	—	66,050	89,120
Non-cash items excluded from operating activities in the consolidated statements of cash flows:				
Decrease in payable on financing arrangements	(3,989)	(16,569)	(4,062)	—
Non-cash items excluded from investing activities in the consolidated statements of cash flows:				
Increase (decrease) in accrued oil and natural gas capital expenditures	166,465	94,415	112,019	177,911
Increase (decrease) in accrued midstream capital expenditures	80,113	2,825	28,917	(15,867)
Decrease in payable on financing arrangements	—	—	—	(23,426)
Non-cash items excluded from financing activities in the consolidated statements of cash flows:				
Increase in payable on financing arrangements	$ 3,989	$ 16,569	$ 4,062	$ 23,426

12. DISCONTINUED OPERATIONS

On December 22, 2010, the Company completed the sale of its interest in natural gas properties and other operating assets in the Fayetteville Shale. On January 7, 2011, the Company completed the sale of its midstream assets in the Fayetteville Shale. For all periods presented, the Company classified the operations associated with the Fayetteville Shale gas gathering systems and equipment, and the other operating assets as *"Loss from discontinued operations, net of income taxes"* in the consolidated statements of operations.

On March 1, 2011, the Company completed the sale of its interest in the Buffalo Hump Ranch located in Van Buren County, Arkansas for approximately $2.1 million in cash. Proceeds from the sale were recorded as a reduction to the carrying value of the land. A loss on sale of approximately $4.3 million was recorded during the first quarter of 2011 in *"Loss from discontinued operations, net of income taxes"* in the consolidated statements of operations. The transaction had an effective date of March 1, 2011.

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. 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.

The following table contains summarized income statement information for the Fayetteville Shale midstream operations and other operating assets for the periods indicated (in thousands):

	Years Ended December 31, 2011	2010
Operating revenues	$ 153	$ 8,875
Operating expenses	43	12,912
Write down of midstream assets and loss on sale	(5,044)	(70,195)
Loss from discontinued operations, before income taxes	(4,934)	(74,232)
Income tax benefit	1,855	28,248
Loss from discontinued operations, net of income taxes	$ (3,079)	$ (45,984)

The following table contains summarized assets held for sale information for the Fayetteville Shale midstream operations for the period indicated (in thousands):

	Year Ended December 31, 2010
Gas gathering systems and equipment	$ 154,724
Accumulated depreciation	(10,548)
Net assets	144,176
Write down of midstream assets	(69,728)
Assets held for sale	$ 74,448

13. EAGLEHAWK FIELD SERVICES

As discussed in Note 2, *"Acquisitions and Divestitures,"* on July 1, 2011, the Company along with its subsidiaries Hawk Field Services and EagleHawk, closed previously announced transactions with Eagle Gathering, an affiliate of Kinder Morgan, including the transfer by Hawk Field Services of a 25% interest in EagleHawk to Eagle Gathering in exchange for cash consideration of approximately $93 million.

EagleHawk, which is managed by Hawk Field Services, owns and operates the gathering and treating assets and business serving the Company's Hawkville and Black Hawk Fields in the Eagle Ford Shale. The Company has dedicated its production from its Eagle Ford Shale leases pursuant to gathering and treating agreements with EagleHawk.

EagleHawk 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 as to 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. We have concluded that the gathering agreements constitute extended continuing involvement under ASC 360-20, and have therefore 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.

The following table presents statement of operations information for EagleHawk for the six months ended June 30, 2013, the year ended December 31, 2012, and for the six month period from July 1, 2011 (the date of EagleHawk's formation) to December 31, 2011:

	Six Months Ended June 30, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
		(in thousands)	
Operating revenues:			
Midstream	$ 23,304	$ 54,092	$ 12,048
Total operating revenues	23,304	54,092	12,048
Operating expenses:			
Taxes other than income	3,176	4,077	621
Gathering, transportation and other	27,320	23,490	7,747
General and administrative	975	1,870	880
Depletion, depreciation and amortization	12,394	17,548	4,670
Total operating expenses	43,865	46,985	13,918
Gain (Loss) from operations	(20,561)	7,107	(1,870)
Other income (expenses):			
Interest expense and other	(4,476)	(16,533)	(4,507)
Total other income (expenses)	(4,476)	(16,533)	(4,507)
Loss from continuing operations before income taxes	(25,037)	(9,426)	(6,377)
Income tax benefit	9,269	3,514	2,279
Net gain (loss)	$ (15,768)	$ (5,912)	$ (4,098)

The following table presents balance sheet information for EagleHawk as of June 30, 2013, and December 31, 2012 and 2011:

	June 30, 2013	December 31, 2012	December 31, 2011
		(in thousands)	
Current assets:			
Cash	$ 30,433	$ 23,508	$ 34,736
Accounts receivable	35,643	28,623	8,025
Prepaids and other	9	61	73
Total current assets	66,085	52,192	42,834
Other operating property and equipment:			
Gas gathering systems and equipment	943,153	742,333	447,335
Other operating assets	954	1,026	1,022
Gross other operating property and equipment	944,107	743,359	448,357
Less—accumulated depreciation	(34,145)	(27,477)	(10,203)
Net other operating property and equipment	909,962	715,882	438,154
Other noncurrent assets:			
Deferred income taxes	9,269	3,514	2,279
Total assets	$ 985,316	$ 771,588	$ 483,267
Current liabilities:			
Accounts payable and accrued liabilities	$ 147,187	$ 49,950	$ 42,109
Total current liabilities	147,187	49,950	42,109
Long-term debt	—	—	—
Other noncurrent liabilities			
Payable to affiliate	294,858	236,197	122,477
Asset retirement obligations	13,008	13,009	9,775
Other	—	7	5
Stockholder's equity:			
Additional paid-in capital	561,834	484,715	312,999
Accumulated deficit	(31,571)	(12,290)	(4,098)
Total stockholder's equity	530,263	472,425	308,901
Total liabilities and stockholder's equity	$ 985,316	$ 771,588	$ 483,267

The following table presents cash flow statement information for EagleHawk for the six months ended June 30, 2013, the year ended December 31, 2012, and for the six month period from July 1, 2011 (the date of EagleHawk's formation) to December 31, 2011:

	Six Months Ended June 30, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
		(in thousands)	
Cash flows from operating activities:			
Net loss	$ (15,768)	$ (5,912)	$ (4,098)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and amortization	12,394	17,548	4,670
Income tax provision (benefit)	(9,269)	(3,514)	(2,279)
Other operating	108	2	500
Change in assets and liabilities:			
Accounts receivable	(9,283)	(18,335)	(8,025)
Prepaid and other	52	12	(127)
Accounts payable and accrued liabilities	27,024	10,190	4,292
Net cash used in operating activities	5,258	(9)	(5,067)
Cash flows from investing activities:			
Other operating property and equipment capital expenditures	(134,113)	(296,655)	(156,750)
Net cash used in investing activities	(134,113)	(296,655)	(156,750)
Cash flows from financing activities:			
Proceeds from borrowings	—	—	82,500
Repayment of borrowings	—	—	(82,500)
Debt issuance costs	—	—	(401)
Payable to affiliate	58,660	113,720	62,846
Contributions from affiliate	93,750	216,838	149,291
Distributions to affiliate	(16,630)	(45,122)	(15,183)
Net cash provided by financing activities	135,780	285,436	196,553
Net increase (decrease) in cash	6,925	(11,228)	34,736
Cash at beginning of period	23,508	34,736	—
Cash at end of period	$ 30,433	$ 23,508	$ 34,736

As discussed in Note 4, *"Long-Term Debt,"* Petrohawk Energy Corporation has issued senior notes that remain outstanding as of the date of this report. Petrohawk has no material independent assets or operations and its senior notes have been guaranteed on an unconditional, joint and several basis, by all of its wholly-owned subsidiaries that have assets or operations. EagleHawk, which is not wholly-owned, and one of the Company's other subsidiaries, Proliq, Inc., are designated as unrestricted subsidiaries for purposes of the Company's Senior Credit Agreement and indentures.

14. RELATED PARTY ARRANGEMENTS AND TRANSACTIONS

Effective January 1, 2013, the Company entered into the Management Services Agreement with BHP Billiton Limited, the parent company of Petrohawk, for BHP Billiton Limited to provide various personnel and payroll services as set forth in the agreement. Former employees of the Company transferred to become employees of BHP Billiton Limited, providing services to the Company and the Company reimburses BHP Billiton Limited for the costs of these services. The total costs incurred under this agreement with BHP Billiton Limited for the six months ended June 30, 2013, were $150.2 million, of which $118.7 million has been cash settled as of June 30, 2013. As a result, the total amount payable to BHP Billiton Limited as of June 30, 2013, is $31.5 million. The following table summarizes the location of the $150.2 million of costs in the Company's consolidated financial statements:

Consolidated Financial	Location of Costs		Amount
			(in thousands)
Balance Sheets	Oil and natural gas properties	$	27,668
Balance Sheets	Gas gathering systems and equipment		14,555
Statements of Operations	General and administrative		86,573
Statements of Operations	Lease operating		17,128
Statements of Operations	Gathering, transportation and other		4,321
		$	150,245

SUPPLEMENTAL OIL AND GAS INFORMATION

Oil and Natural Gas Reserves

Our estimated proved reserves for the six months ended June 30, 2013, and 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 additional information regarding historical reserve estimations, refer to our Forms 10-K for the years ended December 31, 2011 and 2010. Our petroleum engineers currently report to Mr. Abhijit Gadgil, Senior Manager of Petroleum Reserves. Mr. Gadgil has a Master's degree in chemical engineering from Rice University and more than 30 years of industry experience. Mr. Gadgil began his career at Mobil Oil in 1981, gaining increasing levels of responsibility in the US and overseas. He worked for 11 years in the UK and then in Germany in supervisory and management positions in reservoir engineering and reservoir development. He continued his career with ExxonMobil in 2000. Across his career in Mobil and ExxonMobil, Mr. Gadgil was the manager of worldwide corporate reserves for approximately 15 years. Mr. Gadgil has been a member of the Society of Petroleum Engineers for more than 30 years. He served on the board of the Society of Petroleum Engineers Oil and Gas Reserves Committee from 2004 to 2007.

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made. For the first time, the Company added 68,948 Mmcfe proved reserves effective June 30, 2013 associated with future production that will be consumed in operations (typically fuel gas).

The following table illustrates the Company's estimated net proved reserves, including changes, and proved developed reserves for the periods indicated. The oil and natural gas liquids prices as of June 30, 2013, are based on the respective 12-month unweighted average of the first of the month prices of the WTI spot price, which equates to $91.60 per barrel or are based equally on the respective 12-month unweighted average of the first month prices of the WTI and LLS differential spot prices, which equate to $91.60 per barrel and $16.95 per barrel, respectively. The oil and natural gas liquids prices as of December 31, 2012, are based on the respective 12-month unweighted average of the first of the month prices of the WTI spot price, which equates to $94.89 per barrel or are based equally on the respective 12-month unweighted average of the first month prices of the WTI and LLS spot prices, which equate to $94.89 per barrel and $16.90 per barrel, respectively. The oil and natural gas liquids prices as of December 31, 2011 and 2010 are based on the respective 12-month unweighted average of the first of the month prices of the WTI posted price which equates to $96.19 per barrel and $79.43 per barrel, respectively. The oil and natural gas liquids prices were adjusted by lease or field for quality, transportation fees, and regional price differentials. The natural gas prices as of June 30, 2013, and December 31, 2012, 2011, and 2010, are based on the respective 12-month unweighted average of the first of the month prices of the Henry Hub price which equates to $3.47 per Mmbtu, $2.78 per Mmbtu, $4.12 per Mmbtu, and $4.38 per Mmbtu, respectively. All prices are adjusted by lease or field for energy content, transportation fees, and regional price differentials. All prices are held constant in accordance with SEC guidelines. All proved reserves are located in the United States.

	Proved Reserves			
	Oil (MBbls)	**Gas (Mmcf)**	**Natural Gas Liquids (MBbls)**	**Equivalent (Mmcfe)**
Proved reserves, December 31, 2009	8,348	2,699,802	40	2,750,130
Extensions and discoveries[(1)]	16,827	1,709,207	13,810	1,893,029
Purchase of minerals in place	55	5,286	—	5,616
Production	(1,268)	(234,538)	(681)	(246,232)
Sale of minerals in place	(4,547)	(472,783)	(41)	(500,311)
Revision of previous estimates	402	(596,907)	13,977	(510,633)
Proved reserves, December 31, 2010	19,817	3,110,067	27,105	3,391,599
Extensions and discoveries[(1)]	41,079	1,326,073	31,319	1,760,461
Purchase of minerals in place	1,146	42,732	2,613	65,286
Production	(4,715)	(311,178)	(2,843)	(356,526)
Sale of minerals in place	(3,511)	(12,208)	(1,261)	(40,840)
Revision of previous estimates	3,915	(800,348)	169	(775,844)
Proved reserves, December 31, 2011	57,731	3,355,138	57,102	4,044,136
Extensions and discoveries[(1)]	68,949	1,773,745	46,709	2,467,689
Purchase of minerals in place	—	—	—	—
Production	(9,350)	(344,305)	(5,989)	(436,339)
Sale of minerals in place	—	—	—	—
Revision of previous estimates	24,514	(484,050)	9,909	(277,513)
Proved reserves, December 31, 2012	141,844	4,300,528	107,731	5,797,973
Extensions and discoveries[(1)]	94,067	753,541	53,233	1,637,337
Purchase of minerals in place	—	—	—	—
Production	(6,668)	(162,868)	(4,537)	(230,100)
Sale of minerals in place	—	—	—	—
Revision of previous estimates	(24,943)	(1,229,186)	(19,601)	(1,496,439)
Proved reserves, June 30, 2013	204,300	3,662,015	136,826	5,708,771

(1) Includes infill reserves in existing proved fields of 1,573,152 million cubic feet of natural gas equivalent (Mmcfe), 2,154,968 Mmcfe, 1,336,237 Mmcfe, and 1,185,434 Mmcfe at June 30, 2013, and December 31, 2012, 2011, and 2010, respectively.

	Proved Developed Reserves			
	Oil (MBbls)	**Gas (Mmcf)**	**Natural Gas Liquids (MBbls)**	**Equivalent (Mmcfe)**
June 30, 2013	52,122	1,581,519	47,231	2,177,636
December 31, 2012	35,864	1,541,428	32,291	1,950,357
December 31, 2011	13,223	1,434,447	13,534	1,594,989
December 31, 2010	5,756	1,118,699	5,168	1,184,243

	Proved Undeveloped Reserves			
	Oil (MBbls)	Gas (Mmcf)	Natural Gas Liquids (MBbls)	Equivalent (Mmcfe)
June 30, 2013	152,178	2,080,496	89,595	3,531,135
December 31, 2012	105,979	2,759,100	75,440	3,847,616
December 31, 2011	44,507	1,920,691	43,569	2,449,147
December 31, 2010	14,061	1,991,368	21,937	2,207,356

Noteworthy amounts included in the categories of proved reserve changes for the six months ended June 30, 2013 and the years 2012, 2011, and 2010 in the above tables include:

- Extensions and Discoveries:

  2013—Of the 1,637,337 Mmcfe of 2013 Extensions and discoveries, 293,987 Mmcfe related to the Haynesville Shale in Louisiana and Texas and 1,306,746 Mmcfe related to the Eagle Ford Shale in Texas.

  2012—Of the 2,467,689 Mmcfe of 2012 Extensions and discoveries, 1,212,228 Mmcfe related to the Haynesville Shale in Louisiana and Texas and 1,245,221 Mmcfe related to the Eagle Ford Shale in Texas.

  2011—Of the 1,760,461 Mmcfe of 2011 Extensions and discoveries, 881,900 Mmcfe related to the Haynesville Shale in Louisiana and Texas and 849,009 Mmcfe related to the Eagle Ford Shale in Texas.

  2010—Of the 1,893,029 Mmcfe of 2010 Extensions and discoveries, 1,397,470 Mmcfe related to the Haynesville Shale in Louisiana and Texas and 423,880 Mmcfe related to the Eagle Ford Shale in Texas.

- Purchase of Minerals in Place:

  2013—There were no Purchases of minerals in place during the six months ended June 30, 2013.

  2012—There were no Purchases of minerals in place during 2012.

  2011—The 65,286 Mmcfe of 2011 Purchases of minerals in place consisted of two acquisitions of additional interest in existing Hawkville Field holdings in Texas.

  2010—The 5,616 Mmcfe of 2010 Purchases of minerals in place consisted of three acquisitions. 4,810 Mmcfe related to an acquisition in the Eagle Ford Shale area of Texas.

- Sale of Minerals in Place:

  2013—There were no sales of minerals in place during the six months ended June 30, 2013.

  2012—There were no sales of minerals in place during 2012.

  2011—The 40,840 Mmcfe of 2011 Sales of minerals in place consisted of two divestitures. The majority, 39,308 Mmcfe, is related to a third party option to acquire a portion of our interest in the Black Hawk Field of the Eagle Ford Shale.

  2010—The 500,311 Mmcfe of 2010 Sales of minerals in place consisted of eleven divestitures. 318,531 Mmcfe related to a divestiture in the Fayetteville Shale area of Arkansas, and 107,961 Mmcfe related to a divestiture in the Terryville Field in Louisiana.

- Revisions of Previous Estimates:

  2013— Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Due to the re-prioritization of all identified drilling locations, the scheduled drilling of many of the locations that had been scheduled to be drilled within five years as of December 31, 2012 has been delayed beyond the five year timeframe as of June 30, 2013. Of the 1,496,439 MMcfe of downward Revisions of previous estimates, 1,402,961 MMcfe are related to postponing the scheduled development of undrilled locations beyond five years. The remaining amount consists of changes related to pricing, costs, and technical revisions.

2012— Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Due to the re-prioritization of all identified drilling locations, the scheduled drilling of many of the locations that had been scheduled to be drilled within five years as of December 31, 2011 has been delayed beyond the five year timeframe as of December 31, 2012. Of the 277,513 MMcfe of downward Revisions of previous estimates, 439,932 MMcfe are related to postponing the scheduled development of undrilled locations beyond five years. The remaining amount consists of changes related to pricing, costs, and technical revisions.

2011— A majority of the Revision of previous estimates in 2011 was due to the same restrictions under the five year drilling as explained in 2012. Due to the re-prioritization of all identified drilling locations, the scheduled drilling of many of the locations that had been scheduled to be drilled within five years as of December 31, 2010 has been delayed beyond the five year timeframe as of December 31, 2011. Of the 775,844 MMcfe of downward Revisions of previous estimates, 735,508 MMcfe are related to postponing the scheduled development of undrilled locations beyond five years. The remaining amount consists of changes related to pricing, costs, and technical revisions.

2010—A majority of the Revisions of Previous Estimates in 2010 was due to the same restrictions under the five year drilling rule, as explained in 2011. Due to the re-prioritization of all identified drilling locations, the scheduled drilling of many of the locations that had been scheduled to be drilled within five years as of December 31, 2009 has been delayed beyond the allowed five year timeframe as of December 31, 2010. Of the 510,633 Mmcfe of downward Revisions of Previous Estimates, 648,884 Mmcfe related to postponing the scheduled drilling of undrilled locations beyond five years. This was offset by upward Revisions of Previous Estimates consisting of 106,174 Mmcfe related to revisions in prices and costs, and 32,077 Mmcfe related to technical revisions.

The Company's reserves have been estimated using deterministic methods. The total proved reserve additions of 1,637 Bcfe are comprised of 282 Bcfe in proved developed and 1,355 Bcfe in proved undeveloped reserves, and are almost entirely from the Haynesville and Eagle Ford Shales, driven by the active drilling program during 2012 and 2013 in those areas.

For wells classified as proved developed producing where sufficient production history existed, reserves were based on individual well performance evaluation and production decline curve extrapolation techniques. For undeveloped locations and wells that lacked sufficient production history, reserves were based on analogy to producing wells within the same area exhibiting similar geologic and reservoir characteristics, combined with volumetric methods. The volumetric estimates were based on geologic maps and rock and fluid properties derived from well logs, core data, pressure measurements, and fluid samples. Well spacing was determined from drainage patterns derived from a combination of performance-based recoveries and volumetric estimates for each area or field. Proved undeveloped locations were limited to areas of uniformly high quality reservoir properties, between existing commercial producers.

Reliable technologies were used to determine areas where proved undeveloped (PUD) locations are more than one offset away from a producing well. These technologies include seismic data, wire line open hole log data, core data, log cross-sections, performance data, and statistical analysis. In such areas, these data demonstrated consistent, continuous reservoir characteristics in addition to significant quantities of economic estimated ultimate recoveries from individual producing wells. When these techniques were applied to more developed shale reservoirs, such as the Barnett Shale and certain areas in the Fayetteville Shale, they have been empirically demonstrated to be reliable in predicting hydrocarbon recoveries. The experience gained in the Fayetteville Shale over the past several years regarding data gathering and evaluation gave the Company direction when it began development in newer areas, first in the Haynesville Shale in 2008 and in the Eagle Ford Shale in 2009. The Company has been a leader in data gathering and evaluation in these areas and was instrumental in developing consortiums that allow various operators to exchange data. The Company relied only on production flow tests and historical production data, along with the reliable geologic data mentioned above to estimate proved reserves. No other alternative methods or technologies were used to estimate proved reserves.

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization.

	June 30,	December 31,		
	2013	2012	2011	2010
	(in thousands)			
Evaluated oil and natural gas properties	$ 15,329,505	$ 13,213,484	$ 10,509,954	$ 7,520,446
Unevaluated oil and natural gas properties	3,010,761	2,839,950	2,502,435	2,387,037
	18,340,266	16,053,434	13,012,389	9,907,483
Accumulated depletion, depreciation and amortization	(7,297,291)	(6,708,875)	(5,598,420)	(4,774,579)
	$ 11,042,975	$ 9,344,559	$ 7,413,969	$ 5,132,904

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Six Months Ended June 30, 2013	Years Ended December 31, 2012	2011	2010
	(in thousands)			
Property acquisitions costs, proved	$ 14,824	$ 3,711	$ 76,805	$ 26,948
Property acquisitions costs, unproved	35,721	162,395	708,483	607,653
Exploration and extension wells costs	2,131,291	2,801,411	2,210,779	1,719,003
Development costs (1)	124,690	73,747	173,785	242,268
Total costs	$ 2,306,526	$3,041,264	$3,169,852	$2,595,872

(1) Amounts do not include costs for our gas gathering systems and related support equipment.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following Standardized Measure of Discounted Future Net Cash Flows has been developed utilizing ASC 932, *Extractive Activities—Oil and Gas,* (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- future costs and selling prices will probably differ from those required to be used in these calculations;
- due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and
- future net revenues may be subject to different rates of income taxation.

At June 30, 2013, and December 31, 2012, 2011, and 2010, as specified by the SEC, the prices for oil and natural gas used in this calculation were the unweighted 12-month average of the first day of the month prices, except for volumes subject to fixed price contracts. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor.

The Standardized Measure is as follows:

	Six Months Ended June 30, 2013	Years Ended December 31, 2012	2011	2010
		(In thousands)		
Future cash inflows	$37,238,203	$ 30,833,186	$ 21,164,001	$ 15,854,309
Future production costs	(11,632,601)	(9,618,171)	(6,758,663)	(4,695,556)
Future development costs	(7,653,636)	(7,483,886)	(5,581,916)	(4,179,212)
Future income tax expense	(6,318,150)	(3,096,082)	(1,420,846)	(1,301,986)
Future net cash flows before 10% discount	11,633,816	10,635,047	7,402,576	5,677,555
10% annual discount for estimated timing of cash flows	(5,537,771)	(5,164,045)	(3,297,866)	(2,628,030)
Standardized measure of discounted future net cash flows	$6,096,045	$ 5,471,002	$ 4,104,710	$ 3,049,525

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

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during the six months ended June 30, 2013, and each of the years in the three year period ended December 31, 2012:

	Six Months Ended June 30, 2013	Years Ended December 31, 2012	2011	2010
		(in thousands)		
Beginning of year	$ 5,471,002	$ 4,104,710	$ 3,049,525	$ 1,532,125
Sale of oil and natural gas produced, net of production costs	(991,298)	(1,509,865)	(1,449,244)	(854,330)
Purchase of minerals in place	—	—	46,133	5,886
Sales of minerals in place	—	—	(173,073)	(576,571)
Extensions and discoveries	3,581,812	2,975,705	2,613,537	2,275,557
Changes in income taxes, net	(2,207,785)	(727,275)	(44,858)	(437,204)
Changes in prices and costs	964,765	106,467	474,257	1,517,565
Previously estimated development costs incurred	327,613	205,639	90,934	130,411
Net changes in future development costs	(34,644)	545,930	59,772	(202,031)
Revisions of previous quantities	(1,795,223)	(315,351)	(797,721)	(523,042)
Accretion of discount	334,454	459,553	320,639	105,386
Changes in production rates and other	445,349	(374,511)	(85,191)	75,773
End of year	$6,096,045	$ 5,471,002	$ 4,104,710	$ 3,049,525

For six months ended June 30, 2013, the Petrohawk SMOG calculation excludes the impact of Net Operating Loss tax deductions (NOLs) from the calculation of future taxes. For the period ended June 30, 2013, the Change in income taxes, net increased by $2.2 billion on a discounted future net cash flow basis, of which $1.0 billion is related to the exclusion of NOLs with the remaining variance due primarily to the increase in future cash inflows. NOL deductions for BHP Billiton are managed on a regional basis, including a region covering the United States. NOLs may be used by other BHP Billiton entities in BHP Billiton Limited's United States Federal consolidated tax group. However to the extent such NOLs are sourced from Petrohawk, an intercompany receivable would be recognized on Petrohawk's books with the receiving company recording an offsetting intercompany payable. Such intercompany balances are periodically settled in cash.

SELECTED QUARTERLY FINANCIAL DATA

The following table presents selected quarterly financial data derived from the Company's consolidated interim financial statements. The following data is only a summary and should be read with the Company's historical consolidated financial statements and related notes contained in this document.

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
2013				
Total operating revenues	$ 688,902	$ 809,282	n/a	n/a
Income from operations	141,049	56,383	n/a	n/a
(Loss) gain from discontinued operations, net of income taxes	—	—	n/a	n/a
Net (loss) income	21,012	(16,036)	n/a	n/a
Net (loss) income per share(2):				
Basic	—	—	n/a	n/a
Diluted	—	—	n/a	n/a
2012				
Total operating revenues	$ 518,894	$ 487,091	$ 525,608	$ 575,249
Income from operations	46,669	40,492	52,532	43,519
(Loss) gain from discontinued operations, net of income taxes	—	—	—	—
Net (loss) income	(55,353)	(46,421)	(32,666)	(39,992)
Net (loss) income per share(2):				
Basic	—	—	—	—
Diluted	—	—	—	—
2011				
Total operating revenues	$ 493,675	$ 597,440	$ 502,223	$ 506,054
Income from operations	89,156	127,137	36,214	63,503
Loss from discontinued operations, net of income taxes	(2,407)	(752)	(42)	122
Net income (loss)	(31,882)	74,756	81,604	49,670
Net income (loss) per share(1)(2):				
Basic	$ (0.10)	$ 0.25	—	—
Diluted	$ (0.10)	$ 0.24	—	—

(1) Per share amounts are calculated based on *"Net income (loss)"*, which includes the Company's discontinued operations.

(2) On August 25, 2011, in conjunction with the BHP Merger, the Company has 100 shares of common stock which are 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. Petrohawk remains an indirect, wholly owned subsidiary of BHP Billiton Limited at June 30, 2013, and December 31, 2012 and 2011.