DELTA

PETROLEUM CORPORATION

2010 ANNUAL REPORT

DEAR SHAREHOLDERS,

The 2010 fiscal year was truly a pivotal year for Delta Petroleum. Our board of directors gave management three objectives to accomplish by the end of the year. The first objective was the simplification of our asset base. The second objective was the reduction of operating and overhead costs. The third objective was the improvement in the reserves and economics per well in our core field, the Vega Area. By the end of the year all three objectives had been achieved. We simplified our asset base through the sale of half of our working interests in our non-core assets in Texas and the DJ Basin. That transaction enabled Delta to staff specifically for a Piceance-focused business and thereby significantly reduce overhead expense. We were also able to reduce our operating costs significantly in the fourth quarter, which completed the fulfillment of the second objective. Lastly, the third objective of improved per well EUR's was achieved through the use of improved completion methods. Collectively the achievement of these objectives directly results in an increase in proved and probable reserves, production and cash flow, all of which create meaningful value for our shareholders.

In the fourth quarter of 2010, Delta drilled an exploratory test well in the Vega Area targeting deeper shales beneath the Williams Fork section. This well, the Delta 2C-433D, was drilled to a depth of 13,300 feet and encountered significant gas shows and pressures in the Mancos, Niobrara and Frontier formations. The 2C well was followed by a confirmation well targeting the Mancos formation, the Delta 2B-233D well. At the time of this writing, the 2B well has been completed in the Mancos section and has flowed to sales at rates of between two and six million cubic feet per day (MMcf/d). While it is early in our evaluation process, we are very encouraged with the initial results of the 2B well and look forward to similar or better results on the 2C as completion activity continues on that well. Additional production and reserve information regarding these wells will be released in the coming months.

Delta has been dedicated to transformation of the business to a Piceance-focused company that is leaner, more efficient, and capable of delivering meaningful upside from our emerging shale potential in the Vega Area. We believe Delta is now positioned for efficient growth from our core asset. While there are still challenges ahead, we remain optimistic. We embrace our future for the remainder of 2011 and are confident we will continue to improve the core business. We remain convinced that is the most direct path to enhancing shareholder value and we invite you to share that journey with us.

Carl E. Lakey
President and
Chief Executive Officer

Kevin K. Nanke
Treasurer and
Chief Financial Officer

Daniel J. Taylor
Chairman of the Board

DELTA
PETROLEUM CORPORATION

2010 FINANCIAL INFORMATION

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File No. 0-16203

DELTA PETROLEUM CORPORATION

DELTA PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**84-1060803**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
370 17th Street, Suite 4300	
Denver, Colorado	**80202**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(303) 293-9133**

Securities registered under Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.01 par value	**NASDAQ Capital Market**

Securities registered under to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☐ Yes ☐ No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of June 30, 2010, the aggregate market value of voting stock held by non-affiliates of the registrant was approximately $159.7 million, based on the closing price of the Common Stock on the NASDAQ National Market of $0.86 per share. As of March 15, 2011, 286,125,705 shares of registrant's Common Stock, $0.01 par value, were issued and outstanding.

Documents incorporated by reference: The information required by Part III of this Form 10-K is incorporated by reference to the Company's Definitive Proxy Statement for the Company's 2011 Annual Meeting of Stockholders.

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PART I

The terms "Delta," "Company," "we," "our," and "us" refer to Delta Petroleum Corporation and its subsidiaries unless the context suggests otherwise.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We are including the following discussion to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect us and to take advantage of the "safe harbor" protection for forward-looking statements afforded under federal securities laws. From time to time, our management or persons acting on our behalf make forward-looking statements to inform existing and potential security holders about us. Forward-looking statements are generally accompanied by words such as "estimate," "project," "propose," "potential," "predict," "forecast," "believe," "expect," "anticipate," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. Except for statements of historical or present facts, all other statements contained in this Annual Report on Form 10-K are forward-looking statements. The forward-looking statements may appear in a number of places and include statements with respect to, among other things: business objectives and strategies, including our focus on the Vega Area of the Piceance Basin, as well as statements regarding intended value creation; operating strategies; our expectation that we will have adequate cash from operations, credit facility borrowings and other capital sources to satisfy our obligations under our senior credit facility, and to meet future debt service, capital expenditure and working capital requirements; expected announcements of 2011 drilling plans and capital expenditure budget; the availability of capital to fund our working capital needs, our drilling and leasehold acquisition programs, our required payments under our senior credit facility, or any required redemption of our convertible notes; anticipated operating costs, including improvements in our anticipated finding and development costs and overall per unit operating and development costs due to the new fracture stimulation design; impact on costs from use of subsurface injection for water disposal; potential sources of long-term capital or potential corporate transactions such as a sale of the company; acquisition and divestiture strategies; completion and drilling program expectations, processes and emphasis; oil and gas reserve estimates (including estimates of future net revenues associated with such reserves and the present value of such future net revenues); estimates of future production of oil and natural gas; marketing of oil and natural gas; expected future revenues and earnings, and results of operations; future capital, development and exploration expenditures (including the amount and nature thereof); nonpayment of dividends; expectations regarding competition and our competitive advantages; impact of the adoption of new accounting standards and our financial and accounting systems and analysis programs; anticipated compliance with and impact of laws and regulations; and effectiveness of our internal control over financial reporting.

These statements by their nature are subject to certain risks, uncertainties and assumptions and will be influenced by various factors. Should any of the assumptions underlying a forward-looking statement prove incorrect, actual results could vary materially. In some cases, information regarding certain important factors that could cause actual results to differ materially from any forward-looking statement appears together with such statement. In addition, the factors described under Critical Accounting Policies and Risk Factors, as well as other possible factors not listed, could cause actual results to differ materially from those expressed in forward-looking statements, including, without limitation, the following:

- deviations in and volatility of the market prices of both crude oil and natural gas produced by us;
- the availability of capital on an economic basis, or at all, to fund our required payments under our senior credit facility, mandatory redemption of our convertible notes, our working capital needs, and drilling and leasehold acquisition programs, including through potential joint ventures and asset monetization transactions;
- lower natural gas and oil prices negatively affecting our ability to borrow or raise capital, or enter into joint venture arrangements and potentially requiring accelerated repayment of amounts borrowed under our revolving credit facility;
- declines in the values of our natural gas and oil properties resulting in write-downs;
- the impact of current economic and financial conditions on our ability to raise capital;
- a continued imbalance in the demand for and supply of natural gas in the U.S. as a result of depressed general economic conditions;
- the results of exploratory drilling activities;

- the outcome of the ongoing investigation of DHS and certain of its employees, among others, by the Office of the Inspector General, Office of Investigations, of the Export-Import Bank of the United States, and the U.S. Department of Justice;
- expiration of oil and natural gas leases that are not held by production;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production;
- timing, amount, and marketability of production;
- third party curtailment, or processing plant or pipeline capacity constraints beyond our control;
- our ability to find, acquire, develop, produce and market production from new properties;
- the availability of borrowings under our credit facility;
- effectiveness of management strategies and decisions;
- the strength and financial resources of our competitors;
- climatic conditions;
- changes in the legal and/or regulatory environment and/or changes in accounting standards policies and practices or related interpretations by auditors or regulatory entities;
- unanticipated recovery or production problems, including cratering, explosions, fires and uncontrollable flows of oil, gas or well fluids;
- the timing, effects and success of our acquisitions, dispositions and exploration and development activities;
- our ability to fully utilize income tax net operating loss and credit carry-forwards; and
- the ability and willingness of counterparties to our commodity derivative contracts, if any, to perform their obligations.

Many of these factors are beyond our ability to control or predict. These factors are not intended to represent a complete list of the general or specific factors that may affect us.

All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements above. Except as required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of anticipated or unanticipated events or circumstances.

We caution you not to place undue reliance on these forward-looking statements. We urge you to carefully review and consider the disclosures made in this Form 10-K and our reports filed with the SEC that attempt to advise interested parties of the risks and factors that may affect our business.

PART I

Item 1. Business

General

Delta Petroleum Corporation ("Delta" or the "Company") is an independent oil and gas company engaged primarily in the exploration for, and the acquisition, development, production, and sale of, natural gas and crude oil. Our core area of operations is the Rocky Mountain Region, where the majority of our proved reserves, production and long-term growth prospects are located. We have a significant development drilling inventory that consists of proved and unproved locations, the majority of which are located in our Rocky Mountain development projects.

Delta was incorporated in Colorado in 1984. Effective January 31, 2006, Delta reincorporated in Delaware, thereby changing our state of incorporation from Colorado to Delaware. Our principal executive offices are located at 370 17th Street, Suite 4300, Denver, Colorado 80202. Our telephone number is (303) 293-9133. We also maintain a website at http://www.deltapetro.com which contains information about us. Our website is not part of this Form 10-K. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are accessible free of charge at our website.

Recent Developments

Sale of Non-Core Assets
As a result of the strategic alternatives process that we commenced in late 2009, on July 30, 2010, we completed the $130.0 million sale of certain non-core properties to Wapiti Oil & Gas, L.L.C. ("Wapiti"). In conjunction with the completion of this transaction (the "Wapiti Transaction"), we repaid $108.5 million of amounts borrowed under our credit facility, and our borrowing base under the credit facility was reduced to $35.0 million.

Amended Credit Facility
On December 29, 2010, we amended and restated our credit agreement (the "MBL Credit Agreement") whereby the former lenders assigned their interests to Macquarie Bank Limited ("MBL"). The MBL Credit Agreement provides for a revolving loan and a term loan each with a maturity date of January 31, 2012. The revolving loan has an initial borrowing base of $30.0 million and the term loan had an initial commitment of $20.0 million subject to a development plan that must be approved by MBL. See Note 7, "Long-Term Debt" to the accompanying consolidated financial statements.

On March 14, 2011, we entered into an amendment to the MBL Credit Agreement that increased the availability under the term loan at the time from $6.2 million to $25.0 million, and doesn't require repayments of the term loan until the January 2012 maturity date. Specifically, among other changes, the amendment provided for an increase in the term loan commitment from $20.0 million to $25.0 million and removed the requirement that advances under the term loan be subject to approval of a development plan. In addition, so long as Delta is not in default under the MBL Credit Agreement, Delta is not required to comply with certain cash management provisions, including the previous requirement to repay any term loan advances outstanding on a monthly basis with 100% of net operating cash flows. See Note 20, "Subsequent Events" to the accompanying consolidated financial statements.

Proceeds from the Wapiti Transaction and the MBL Credit Agreement were used to substantially reduce amounts outstanding under our prior credit facility, as well as to extend the date from January 15, 2011 to January 31, 2012, and to fund capital expenditures.

Overview and Strategy

Our corporate strategy is to focus on increasing stockholder value, specifically by creating incremental value from our core asset, the Vega Area of the Piceance Basin.

Maintain a disciplined operational focus on our core asset

During 2010, we streamlined our business to focus on our core asset, the Vega Area of the Piceance Basin. As of December 31, 2010, the Vega Area comprised approximately 84% of our proved reserves and with its undeveloped leasehold potential comprises virtually all of our long-term growth prospects. We divested of many of our non-core assets and interests in producing fields in Texas and other non-core areas which allowed us to reduce our overhead and operating expenses, while also providing capital to deploy in the Vega Area. While we retain working interests in certain fields outside our core area, they are now operated by third parties and we expect limited capital expenditures in these areas in the future. We will continue to evaluate the divestiture of our remaining working interest in these non-operated assets.

Continue to utilize superior completion methodology to maximize the reserves per well

The Piceance Basin generally has consistent and predictable geology. The consistent and predictable geology throughout the Vega Area allows us to benefit from meaningful economies of scale in both our drilling and completion activities. During the past year we have utilized a larger well completion design that has improved our initial production rates and our expected reserve recovery per well. The revision to the completion method is in the fracture stimulation procedure, which is much larger than prior fracture stimulation designs. The new fracture stimulation design is referred to as "generation four" or "Gen IV" as it is the fourth iteration of our fracture stimulation design for wells in the Vega Area. The improved frac design increased our gross average well recoveries from 1.15 Bcfe to 1.60 Bcfe. This incremental improvement in reserves per well is expected to provide for a lower finding and development cost per Mcfe, which equates to lower overall per unit operating and development costs.

Maintain lower operating and overhead costs

In the latter half of 2010 we were able to reduce both our operating and overhead costs. As a result of the divestiture of non-core assets, we were able to reduce our staff and maintain a team solely focused on the development of Vega which enabled us to reduce our general and administrative expenses. We also substantially reduced our operating costs, particularly in the fourth quarter, both on an absolute basis and on a per Mcfe basis. Much of the operating cost reduction was achieved by using the water we produce from our wells in the completion activity. Water disposal is the largest single operating expense in the Vega Area. This efficient utilization of our produced water enabled us to significantly reduce our water disposal costs for the fourth quarter. Subsequent to year end we terminated a contract with a water treatment service provider for the Vega Area, which resulted in the elimination of an ongoing future expense of approximately $500,000 per month for a ten year period in exchange for a one-time payment of $1.5 million. The termination of this contract allows us to use alternative methods of water treatment and disposal that are more suitable for the amount of water that is currently being produced at the field, and management believes that the use of subsurface injection for water disposal is a much more viable and cost effective approach at the present time. In addition to the water disposal wells we currently utilize, we anticipate converting four wells in the field to water disposal wells and possibly drilling another. The existing wells that are targeted for water disposal are old wells that have minimal or no gas production. We are currently in the process of obtaining the necessary permits to inject our produced water into the four existing wells, which will help maintain our overall operating costs at the reduced levels.

Quantify reserve potential in the deeper zones beneath the Williams Fork section

During the fourth quarter of 2010 we spud a well in the Vega Area to drill to deeper, potentially productive, zones below the Williams Fork section of the Mesa Verde formation. Our interest in testing the deeper zones originated with our understanding that other third party operators in the Piceance Basin with analogous geology had experienced successful tests in formations beneath the Williams Fork. We began completion activities on the deep test well subsequent to year end 2010. We have also spud a second well that will target the section immediately beneath the Williams Fork. As the drilling and completion activities are finished we will continue our evaluation of the reserve potential, if any, in these deeper zones.

Solidify our acreage position at the Vega Area

Our leasehold position at the Vega Area totals approximately 22,375 net acres. Over 86% of this acreage is not subject to lease expiration as it is held by production (HBP). During 2011, we have approximately 1,810 net acres subject to primary term expiration. However, approximately 1,600 net acres which are subject to 2011 expiration will be converted to HBP with the drilling and completion of a single well. We are planning on drilling this well during 2011 and will make all financially prudent efforts to limit other future lease expirations at the Vega Area.

Maximize Stockholder Value

We are currently exploring a variety of options to maximize value to our stockholders. We intend to continue to focus on increasing our reserves, production and revenues through improved frac technology and exploratory efforts at our Vega acreage, while at the same time reducing our expenses on a per unit basis. We believe that if we are able to meet these objectives, it is likely that opportunities to further increase shareholder value will become available to us, including, without limitation, access to capital markets, sales of assets for a premium or a sale of the entire company.

Experienced management and operational team

Our senior management team has, on average, over 25 years of experience in the oil and gas industry. Our management team is supported by an active board of directors with extensive experience in the capital markets and in the oil and gas industry. We retain highly experienced personnel in our production, drilling and land management teams. Our senior managers in our technical teams all have decades of experience in their respective disciplines.

Operations

During the year ended December 31, 2010, we were primarily engaged in two industry segments, namely the acquisition, exploration, development, and production of oil and natural gas properties and related business activities, and contract oil and natural gas drilling operations.

Oil and Gas Reserves

The following table presents reserve and production information regarding our primary oil and natural gas areas of operation as of December 31, 2010:

	Oil (Mbbl)	Natural Gas (Mmcf)	Total (Mmcfe)	2010 Production (MMcfe/d)[(1)]
Proved Developed				
Rocky Mountain Region	733	108,275	112,670	35.1
Gulf Coast Region	844	4,215	9,281	8.8
Other	282	44	1,737	2.0
Total	1,859	112,534	123,688	45.9
Proved Undeveloped				
Rocky Mountain Region[(2)]	61	10,145	10,511	
Gulf Coast Region	-	-	-	
Other	-	-	-	
Total	61	10,145	10,511	
Total Proved Reserves[(3)]	1,920	122,679	134,199	

(1) MMcfe/d means million cubic feet of gas equivalent per day.

(2) At December 31, 2010, based on our more limited development plan given our current capital availability, we were unable to book as proved reserves substantially all of our undeveloped locations in the Piceance Basin that would otherwise qualify as proved. Proved undeveloped reserves at December 31, 2010 in the table above include only our five drilled but uncompleted wells in the Vega Area and non-operated Piceance Basin wells for which we will incur no additional capital due to the carry provisions of the February 2008 agreement with Encana.

(3) Based on historical first of month twelve month average spot prices of $79.61 per Bbl for WTI oil and $3.95 per MMBtu for CIG natural gas, in each case adjusted for differentials, contractual deducts and similar factors.

We intend to focus our 2011 capital spending on the development of our core area of operations in the Rocky Mountains, the Piceance Basin, to the extent that cash on hand, cash flows and available capital through our credit facility, joint ventures or asset sales are adequate to fund our plans.

Our oil and gas operations have been comprised primarily of production of oil and natural gas, drilling exploratory and development wells and related operations and acquiring and selling oil and natural gas properties. Directly or through wholly-owned subsidiaries, and through Amber Resources Company of Colorado ("Amber"), our 91.68% owned subsidiary, and CRB Partners, LLC ("CRBP"), we currently own producing and non-producing oil and natural gas interests, undeveloped leasehold interests and related assets in ten states and interests in a producing Federal unit offshore California. We intend to continue our emphasis on the drilling of development wells, primarily in the Piceance Basin of Colorado.

We have oil and gas leases with governmental entities and other third parties who enter into oil and gas leases or assignments with us in the regular course of our business. We have no material patents, licenses, franchises or concessions that we consider significant to our oil and gas operations. The nature of our business is such that it is not seasonal, we do not engage in any research and development activities and we do not maintain or require a substantial amount of products, customer orders or inventory. Our oil and gas operations are not subject to renegotiations of profits or termination of contracts at the election of the federal government. We operate the properties that comprise the majority of our production and reserves, giving us more ability to control the costs incurred.

Contract Drilling Operations

Through a series of transactions in 2004 and 2005, we acquired and now own an interest in DHS, a contract drilling company that is headquartered in Casper, Wyoming. During the second quarter of 2006, DHS engaged in a reorganization transaction pursuant to which it became a subsidiary of DHS Holding Company, a Delaware corporation, and the Company's ownership interest became an interest in DHS Holding Company. References to DHS herein shall be deemed to include both DHS Holding Company and DHS, unless the context otherwise requires. DHS is a consolidated entity of Delta. Delta currently owns a 49.8% interest in DHS Holding Company, controls the board of directors of DHS and has priority access to all of DHS's drilling rigs. At December 31, 2010, DHS owned 18 drilling rigs with depth ratings of approximately 10,000 to 25,000 feet, of which 10 are currently under contract.

The following table presents our average drilling revenue per day and rigs available for service for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	2009	2008
Average number of rigs owned during period	18	18.5	16.7
Total rig days(1)	2,805	854	5,032
Average drilling revenue per day	$ 15,511	$ 16,730	$ 18,188

(1)Total rig days includes the number of days each rig was under contract.

During 2009, we experienced a significant reduction in rig utilization from 2008 (as reflected in rig days shown above) as operators cut their capital budgets and suspended drilling operations in response to the low commodity price environment that existed for the majority of the year. In view of the abundance of drilling rig capacity during 2009, drilling day rates were lower in 2009 than 2008. With Rockies gas prices recently increasing to more favorable levels, drilling day rates stabilized during 2010 and rig days under contract improved as compared to 2009.

DHS also owns 100% of Chapman Trucking, which was acquired in November 2005. Employing its 28 trucks and 38 trailers, Chapman provides moving services for DHS and for third party drilling rigs. Chapman Trucking continues to market trucking services in the Casper, Wyoming area.

Subsequent to year-end, the Board of Directors of DHS engaged transaction advisors to commence a strategic alternatives process, focused on a sale of the company or substantially all of its assets. There can be no assurance that the terms offered by a potential buyer, if any, will be acceptable to the DHS shareholders. Additionally, the consummation of certain transactions are subject to the approval of DHS's senior lender and the proceeds received will be required to be used to pay down amounts outstanding under its DHS credit facility.

Contracts – Drilling

We earn our DHS contract drilling revenues under day work or turnkey contracts which vary depending upon the rig employed, equipment and services supplied, geographic location, term of the contract, competitive conditions and other variables. Our contracts generally provide for a basic day rate during drilling operations, with lower rates or no payment for periods of equipment breakdown. When a rig is mobilized or demobilized from an operating area, a contract may provide for different day rates during the mobilization or demobilization. Turnkey contracts are accounted for on a percentage-of-completion basis. Contracts to employ our drilling rigs have a term based on a specified period of time or the time required to drill a specified well or number of wells. The contract term in some instances may be extended by the customer exercising options for the drilling of additional wells or for an additional term, or by exercising a right of first refusal. Most contracts permit the customer to terminate the contract at the customer's option without paying a termination fee.

Markets

The principal products produced by us are crude oil and natural gas. The products are generally sold at the wellhead to purchasers in the immediate area where the product is produced. The principal markets for oil and natural gas are refineries and transmission companies which have facilities near our producing properties.

DHS's principal market is the drilling of oil and natural gas wells for us and others in the Rocky Mountain and onshore Gulf Coast Regions. To the extent that DHS rigs are not fully utilized by us, DHS typically contracts with other oil and gas companies on a single-well basis, with optional extensions.

Distribution

Oil and natural gas produced from our wells is normally sold to various purchasers as discussed below. Oil is picked up and transported by the purchaser from the wellhead. In some instances we are charged a fee for the cost of transporting the oil which is deducted from or accounted for in the price paid for the oil. Natural gas wells are connected to pipelines generally owned by the natural gas purchasers. A variety of pipeline transportation charges are usually included in the calculation of the price paid for the natural gas.

Competition

We encounter strong competition from major oil companies and independent operators in acquiring properties and leases for the exploration for, and the development and production of, natural gas and crude oil. Competition is particularly intense with respect to the acquisition of desirable undeveloped oil and gas leases. The principal competitive factors in the acquisition of undeveloped oil and gas leases include the availability and quality of staff and data necessary to identify, investigate and purchase such leases, and the financial resources necessary to acquire and develop such leases. Many of our competitors have substantially greater financial resources, and more fully developed staffs and facilities than ours. In addition, the producing, processing and marketing of natural gas and crude oil are affected by a number of factors which are beyond our control, the effect of which cannot be accurately predicted. See "Item 1A. Risk Factors."

To the extent that the DHS drilling rigs are not fully utilized by us for any reason, DHS seeks to drill wells for our competitors in the oil and gas business in order to achieve revenues to sustain its operations. To a large degree, the success of DHS's business is dependent upon the level of capital spending by oil and gas companies for exploration, development and production activities. Decreases in the price of natural gas and oil, particularly natural gas, during late 2008 and through late 2009 have had a material adverse impact on exploration, development, and production activities by all of DHS's customers, including us, which materially affected and continue to affect DHS's financial position, results of operations and cash flows.

Raw Materials

The principal raw materials and resources necessary for the exploration and development of natural gas and crude oil are leasehold prospects under which natural gas and oil reserves may be discovered, drilling rigs and related equipment to drill for and produce such reserves and knowledgeable personnel to conduct all phases of gas and oil operations. Decreases in demand for oil and gas in late 2008 through late 2009 have resulted in equipment and supplies used in our business being available from multiple sources.

Major Customers

During the year ended December 31, 2010, we had two companies that individually accounted for 45% and 18% of our total oil and gas sales. Although a substantial portion of production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business as other customers or markets would be accessible to us. See Note 3 to our accompanying consolidated financial statements for additional information.

During the year ended December 31, 2010, DHS had two companies that individually accounted for 37% and 17% of total drilling revenues other than Delta. Our recent and projected reduced level of drilling activities and the loss of other customers has had and will have a material adverse effect on DHS if there is a sustained period of lower prices of natural gas and oil as discussed above.

Government Regulation of the Oil and Gas Industry

General

Our business is affected by numerous federal, state and local laws and regulations, including those relating to protection of the environment, public health, and worker safety. The technical requirements of these laws and regulations are becoming increasingly expensive, complex, and stringent. Non-compliance with these laws and regulations may result in imposition of substantial liabilities, including civil and criminal penalties. In addition, certain laws impose strict liability for environmental remediation and other costs. Changes in any of these laws and regulations could have a material adverse effect on our business. In light of the many uncertainties with respect to future laws and regulations, we cannot predict the overall effect of such laws and regulations on our future operations. Nevertheless, the trend in environmental regulation is to place more restrictions and controls on activities that may affect the environment, and future expenditures for environmental compliance or remediation may be substantially more than we expect.

We believe that our operations comply in all material respects with all applicable laws and regulations and that the existence and enforcement of such laws and regulations have no more restrictive effect on our method of operations than on other similar companies in the energy industry. Accidental leaks and spills requiring cleanup may occur in the ordinary course of business, and the costs of preventing and responding to such releases are embedded in the normal costs of doing business. In addition to the costs of environmental protection associated with our ongoing operations, we may incur unforeseen investigation and remediation expenses at facilities we formerly owned and operated or at third-party owned waste disposal sites that we have used. Such expenses are difficult to predict and may arise at sites operated in compliance with past industry standards and procedures.

The following discussion contains summaries of certain laws and regulations and is qualified in its entirety by the foregoing.

Environmental regulation

Our operations are subject to numerous federal, state, and local environmental laws and regulations concerning our oil and gas operations, products and other activities. In particular, these laws and regulations govern, among other things, the issuance of permits associated with exploration, drilling and production activities, the types of activities that may be conducted in environmentally protected areas such as wetlands and wildlife habitats, the release of emissions into the atmosphere, the discharge and disposal of regulated substances and waste materials, offshore oil and gas operations, the reclamation and abandonment of well and facility sites, and the remediation of contaminated sites.

Governmental approvals and permits are currently, and will likely in the future be, required in connection with our operations, and in the construction and operation of gathering systems, storage facilities, pipelines and transportation facilities (midstream operations). The success of obtaining, and the duration of, such approvals are contingent upon a significant number of variables, many of which are not within our control, or those of others involved in midstream operations. To the extent such approvals are required and not granted, operations may be delayed or curtailed, or we may be prohibited from proceeding with planned exploration or operation of facilities.

Environmental laws and regulations are expected to have an increasing impact on our operations, although it is impossible to predict accurately the effect of future developments in such laws and regulations on our future earnings and operations. Some risk of environmental costs and liabilities is inherent in our operations and products, as it is with other companies engaged in similar businesses, and there can be no assurance that material costs and liabilities will not be incurred; however, we do not currently expect any material adverse effect upon our results of operations or financial position as a result of compliance with such laws and regulations.

Recent and future environmental regulations, including additional federal and state restrictions on greenhouse gas ("GHG") emissions that have been or may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce. The U.S. Environmental Protection Agency (the "EPA") has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress is considering "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. We will continue to monitor the establishment of these regulations through industry trade groups and other organizations in which we are a member. Similar regulations may be adopted by other states in which we operate or by the federal government.

Although future environmental obligations are not expected to have a material adverse effect on our results of operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur substantial environmental liabilities or costs.

Because we are engaged in acquiring, operating, exploring for and developing natural resources, in addition to federal laws we are subject to various state and local provisions regarding environmental and ecological matters. Compliance with environmental laws may necessitate significant capital outlays, may materially affect our earnings potential, and could cause material changes in our proposed business. In the past these laws have not had a material adverse effect on our business. However, during 2009, the Colorado Oil and Gas Conservation Commission ("COGCC") adopted new regulations related to oil and gas development which are intended to prevent or mitigate environmental impacts of oil and gas development and include the permitting of wells. It should be noted in that regard that we conduct a significant portion of our business in Colorado and have the majority of our drilling capital budgeted there for 2011. Although we do not anticipate that expenditures to comply with existing environmental laws in any of the areas that we operate will change materially during 2011, we cannot be certain as to the nature and impact any new statutes implemented in Colorado or in other states in which we conduct our business may have on our operations.

Hazardous substances and waste disposal

We currently own or lease interests in numerous properties that have been used for many years for natural gas and crude oil production. Although the operator of such properties may have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us. In addition, some disposal sites that we have used have been operated by third parties over whom we had no control. The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") and comparable state statutes impose strict joint and several liability on current and former owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. The federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes govern the management and disposal of wastes. Although CERCLA currently excludes unaltered, raw petroleum from cleanup liability, petroleum constituents blended with other contaminants are not exempt, and many state laws affecting our operations impose separate clean-up liability regarding petroleum and petroleum-related products.

In addition, although RCRA currently classifies certain exploration and production wastes as "non-hazardous," state agencies such as COGCC are increasingly regulating such non-hazardous waste under separate regulatory programs which impose tighter storage, handling, generation, disposal, and record keeping obligations. In addition, such wastes could be reclassified as hazardous wastes, thereby making such wastes subject to more stringent handling and disposal requirements. If such a change were to occur, it could have a significant impact on our operating costs, as well as on the oil and gas industry in general.

Oil spills

The federal Clean Water Act ("CWA") and the federal Oil Pollution Act of 1990, as amended ("OPA"), impose significant penalties and other liabilities with respect to oil spills that damage or threaten navigable waters of the United States. Under the OPA, (i) owners and operators of onshore facilities and pipelines, (ii) lessees or permittees of an area in which an offshore facility is located, and (iii) owners and operators of tank vessels ("Responsible Parties") are strictly liable on a joint and several basis for removal costs and damages that result from a discharge of oil into the navigable waters of the United States. These damages include, for example, natural resource damages, real and personal property damages and economic losses. OPA limits the strict liability of Responsible Parties for removal costs and damages that result from a discharge of oil to $350.0 million in the case of onshore facilities, $75.0 million plus removal costs in the case of offshore facilities, and in the case of tank vessels, an amount based on gross tonnage of the vessel; however, these limits do not apply if the discharge was caused by gross negligence or willful misconduct, or by the violation of an applicable Federal safety, construction or operating regulation by the Responsible Party, its agent or subcontractor or in certain other circumstances. To date, we have not had any such material spills.

In addition, with respect to certain offshore facilities, OPA requires evidence of financial responsibility in an amount of up to $150.0 million. Tank vessels must provide such evidence in an amount based on the gross tonnage of the vessel. Failure to comply with these requirements or failure to cooperate during a spill event may subject a Responsible Party to civil or criminal enforcement actions and penalties.

In light of the recent off-shore spill in the Gulf, these limits and related liability provisions are under significant scrutiny, and may be changed going forward. This could impose additional obligations on us, as well as on the oil and gas industry in general.

Under our various agreements, we have primary liability for oil spills that occur on properties for which we act as operator. With respect to properties for which we do not act as operator, we are generally liable for oil spills to the extent of our interest as a non-operating working interest owner.

Offshore production

Offshore oil and gas operations in U.S. waters are subject to regulations of the United States Department of the Interior ("DOI"), Bureau of Ocean Energy and Management, Regulation and Enforcement ("BOEMRE"). In response to the recent off-shore spill in the Gulf, the BOEMRE has been split into three separate agencies. One new agency – the Office of Natural Resources Revenue – began operations in October 2010. The two other new agencies – the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement – are expected to be fully implemented by October 1, 2011. The rules of the new agencies will be under significant scrutiny and may be changed from existing BOEMRE rules going forward. Currently, BOEMRE imposes strict liability upon the lessee under a federal lease for the cost of clean-up of pollution resulting from the lessee's operations. As a result, such a lessee could be subject to possible liability for pollution damages. In the event of a serious incident of pollution, the DOI may require a lessee under federal leases to suspend or cease operations in the affected areas.

We do not act as operator for any of our offshore California properties. The operators of our offshore California properties are primarily liable for oil spills and are required by BOEMRE to carry certain types of insurance and to post bonds in that regard. There is no assurance that applicable insurance coverage is adequate to protect us.

Abandonment Obligations

We are responsible for costs associated with the plugging of wells, the removal of facilities and equipment and site restoration on our oil and natural gas properties according to our pro rata ownership. We account for our asset retirement obligations under applicable FASB guidance which requires entities to record the fair value of a liability for retirement obligations of acquired assets. We had a discounted asset retirement obligation of approximately $5.1 million at December 31, 2010. Estimates of abandonment costs and their timing may change due to many factors, including actual drilling and production results, inflation rates and changes to environmental laws and regulations. Estimated asset retirement obligations are added to net unamortized historical oil and gas property costs for purposes of computing depreciation, depletion and amortization expense charges.

Employees

At December 31, 2010 we had approximately 39 full-time employees. Additionally, certain operators, engineers, geologists, geophysicists, landmen, pumpers, draftsmen, title attorneys and others necessary for our operations are retained on a contract or fee basis as their services are required.

Item 1A. Risk Factors.

An investment in our securities involves a high degree of risk. You should carefully read and consider the risks described below before deciding to invest in our securities. The occurrence of any such risks may materially harm our business, financial condition, results of operations or cash flows. In any such case, the trading price of our common stock and other securities could decline, and you could lose all or part of your investment. When determining whether to invest in our securities, you should also refer to the other information contained in this Annual Report on Form 10-K, including our consolidated financial statements and the related notes, and in our subsequent filings with the Securities and Exchange Commission.

Risks Related To Our Business And Industries.

Inadequate liquidity could materially and adversely affect our business operations in the future.

Our efforts to improve our liquidity position will be challenging given the current economic climate and the Company's financial condition. Current economic fundamentals portray an uncertain outlook for natural gas commodity prices in particular. These economic conditions have resulted in a decline in our revenues and available capital, and have caused us to significantly decrease our drilling activities and operations in 2009 and 2010 as compared to prior periods. Although we have entered into derivative contracts that reduce our exposure to changes in commodity prices, our ability to maintain adequate liquidity through 2011 will nevertheless depend significantly on adequate pipeline capacity, maintaining low operating expenses, focused capital spending, generation of additional working capital, and the availability of funding. We are committed to exploring all options because there is no assurance that industry commodity price or capital markets conditions will improve in the near term.

Consummation of a strategic transaction, which may include a sale of the company, a sale of assets, or joint venture or partnership arrangement may be necessary to fund our long-term capital expenditure and working capital needs.

In 2010, we successfully completed a non-core asset divestiture for gross proceeds of $130.0 million, as well as entered into an amended and restated credit facility thereby extending its maturity from January 2011 to January 2012. In late 2010 we resumed completion activities in the Piceance Basin and spud an exploratory test well to evaluate reservoir potential below the already proven Williams Fork section on our Piceance Basin leasehold. Our borrowings under our MBL Credit Agreement are due on January 31, 2012. Additionally, the holders of our 3¾% senior convertible notes have the option to require the Company to purchase the notes held by them on May 1, 2012. If we are unable to complete any additional capital raising transactions, we may not be able to repay the amounts outstanding under the credit facility when due or redeem our convertible notes if required by the note holders without obtaining other sources of capital including a sale of the company, additional asset sales or other alternative financing.

Our level of indebtedness could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in the economy or our industry and prevent us from meeting our obligations under our indebtedness, which would adversely affect our ability to operate as a going concern.

As of December 31, 2010, our total outstanding long-term liabilities were $357.0 million, including $69.6 million of outstanding borrowings drawn under DHS's credit facility which are classified as current in the accompanying consolidated balance sheet. Our long-term indebtedness represented 41.1% of our total book capitalization at December 31, 2010. Based on our $30.0 million borrowing base and availability under our term loan, we had $7.1 million available under our credit facility as of December 31, 2010 and $26.4 million as of March 16, 2011. Our 7% senior unsecured notes indenture imposes limitations on our incurrence of additional secured borrowings. Our degree of leverage could have important consequences, including the following:

- it may limit our ability to obtain additional debt or equity financing for working capital, capital expenditures, further exploration, debt service requirements, acquisitions and general corporate or other purposes;

- a substantial portion of our cash flows from operations will be dedicated to the payment of principal and interest on our indebtedness and will not be available for other purposes, including our operations, capital expenditures and future business opportunities;

- the debt service requirements of other indebtedness in the future could make it more difficult for us to satisfy our financial obligations;

- certain of our borrowings, including borrowings under our credit facility, are at variable rates of interest, exposing us to the risk of increased interest rates;

- as we have pledged most of our oil and natural gas properties and the related equipment, inventory, accounts and proceeds as collateral for the borrowings under our credit facility, they may not be pledged as collateral for other borrowings and would be at risk in the event of a default thereunder;

- it may limit our ability to adjust to changing market conditions and place us at a competitive disadvantage compared to our competitors that have less debt;

- we are vulnerable in the present downturn in general economic conditions and in our business, and we will likely be unable to carry out capital spending and exploration activities in excess of those that are currently planned; and

- we have recently been, and may from time to time be, out of compliance with covenants under our credit facility, which will require us to seek waivers from our banks, which may be more difficult to obtain in the current economic environment.

We may incur additional debt, including secured indebtedness, or issue preferred stock in order to maintain adequate liquidity and develop our properties to the extent desired. A higher level of indebtedness and/or preferred stock increases the risk that we may default on our obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, natural gas and oil prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets, the number of shares of capital stock we have authorized, unissued and unreserved and our performance at the time we need capital.

In addition, our bank borrowing base is subject to periodic redetermination. Any reduction to our borrowing base could require us to repay indebtedness in excess of the borrowing base, or we might be required to provide the lenders with additional collateral. Further, our credit facility matures on January 31, 2012 at which time all amounts outstanding thereunder will be due and payable. At current commodity prices, we do not project that we will be able to repay such borrowings without completing one or more capital raising transactions, obtaining an extension of the credit facility from the lender, or entering into a new credit facility. Accordingly, we are currently engaged in seeking capital from a number of sources, including asset sales, potential joint ventures or similar industry partnerships, or an outright sale of the Company. Failure to obtain adequate capital may adversely affect our ability to operate as a going concern.

Natural gas and oil prices are volatile. Lower prices have adversely affected our financial position, financial results, cash flows, access to capital and ability to grow.

Our revenues, operating results, profitability and future rate of growth depend primarily upon the prices we receive for the natural gas and oil we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow under our credit facility is subject to periodic redeterminations based on prices specified by our lender at the time of redetermination.

Historically, the markets for natural gas and oil have been volatile and they are likely to continue to be volatile. Wide fluctuations in natural gas and oil prices may result from relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of natural gas and oil;

- weather conditions;

- the level of consumer demand;

- the price and availability of alternative fuels;
- the proximity and capacity of natural gas pipelines and other transportation facilities;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the nature and extent of regulation relating to carbon and other greenhouse gas emissions;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas and oil price movements with any certainty. Declines in natural gas and oil prices not only reduce revenue, but also reduce the amount of natural gas and oil that we can produce economically and, as a result, have had, and could in the future have a material adverse effect on our financial condition, results of operations, cash flows and reserves. Further, natural gas and oil prices do not move in tandem. Because approximately 91% of our reserves at December 31, 2010 were natural gas reserves, we are more affected by movements in natural gas prices.

Further reduction of our credit ratings, or failure to restore our credit ratings to higher levels, could have a material adverse effect on our business and our ability to attract capital investment.

Our credit ratings have been downgraded to historically low levels. Our unsecured debt is currently assigned a non-investment grade rating by each of the four nationally recognized statistical rating organizations. The decline in our credit ratings reflects the agencies' concerns over our financial strength. Our current credit ratings reduce our access to the unsecured debt markets and will unfavorably impact our overall cost of borrowing. Further downgrades of our current credit ratings or significant worsening of our financial condition could also result in increased demands by our suppliers for accelerated payment terms or other more onerous supply terms.

The current financial environment may have impacts on our business and financial condition that we cannot predict.

The continued instability in the global financial system and related limitation on availability of credit may continue to have an impact on our business and our financial condition, and we may continue to face challenges if conditions in the financial markets do not improve. Once adopted, our operating and capital budget for 2011 will most likely be funded with anticipated internally generated cash flow and other available sources of liquidity. Such sources historically have not been sufficient to fund all of our expenditures, and we have relied on the capital markets and asset monetization transactions to provide us with additional capital. Our ability to access the capital markets has been restricted as a result of the economic downturn and related financial market conditions and may be restricted in the future when we would like, or need, to raise capital. The difficult financial environment may also limit the number of prospects for our potential joint venture or asset monetization transactions that we are marketing or reduce the values we are able to realize in those transactions, making these transactions uneconomic or difficult to consummate and limit our ability to attract joint venture partners to develop our reserves. The economic situation could also adversely affect the collectability of our trade receivables and cause our commodity hedging arrangements, if any, to be ineffective if our counterparties are unable to perform their obligations. Additionally, the current economic situation could lead to further reduced demand for natural gas and oil, or lower prices for natural gas and oil, or both, which would have a negative impact on our revenues.

Information concerning our reserves is uncertain.

There are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our control. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of oil and natural gas reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and natural gas prices, availability and terms of financing, expenditures for future development and exploitation activities, and engineering and geological interpretation and judgment. Reserves and future cash flows may also be subject to material downward or upward revisions based upon production history, development and exploitation activities, oil and natural gas prices and regulatory changes. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and value of cash flows from those reserves may vary significantly from our assumptions and estimates. In addition, reserve engineers may make different estimates of reserves and cash flows based on the same data. Further, the difficult financing environment may inhibit our ability to finance development of our reserves in the future.

The estimated quantities of proved reserves and the discounted present value of future net cash flows attributable to those reserves as of December 31, 2010, 2009 and 2008 included in our periodic reports filed with the SEC were prepared by our independent reserve engineers in accordance with the rules of the SEC, and are not intended to represent the fair market value of such reserves. As required by the SEC, the estimated discounted present value of future net cash flows from proved reserves is generally based on prices and costs as required by the SEC on the date of the estimate, while actual future prices and costs may be materially higher or lower. For 2008, in accordance with SEC rules at the time, proved reserves were based on single day year-end prices. For 2010 and 2009, in accordance with new SEC rules, proved reserves were prepared based on the twelve-month average first of month historical price. In addition, the 10% discount factor, which the SEC requires to be used to calculate discounted future net revenues for reporting purposes, is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and gas industry in general.

We may not be able to replace production with new reserves.

Our reserves will decline significantly as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration drilling activities. Our future oil and natural gas production is highly dependent upon our level of success in finding or acquiring additional reserves that are economically feasible and developing existing proved reserves, which is in turn dependent on the availability of capital to fund such acquisition and development activity.

Exploration and development drilling may not result in commercially productive reserves.

We do not always encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in wells we drill or participate in. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment;
- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions; and
- compliance with environmental and other governmental requirements.

If oil or natural gas prices decrease or exploration and development efforts are unsuccessful, we may be required to take further writedowns.

In the past, we have been required to write down the carrying value of our oil and gas properties and other assets. There is a risk that we will be required to take additional writedowns in the future, which would reduce our earnings and stockholders' equity. A writedown could occur when oil and natural gas prices are low or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration and development results.

We account for our crude oil and natural gas exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. If the carrying amount of our oil and gas properties exceeds the estimated undiscounted future net cash flows, we will adjust the carrying amount of the oil and gas properties to their estimated fair value.

We review our oil and gas properties for impairment quarterly or whenever events and circumstances indicate that the carrying value may not be recoverable. Once incurred, a writedown of oil and gas properties is not reversible at a later date even if gas or oil prices increase. Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that would require us to record an impairment of the recorded carrying values associated with our oil and gas properties. As a result of this assessment, during the year ended December 31, 2010, we recorded impairment provisions related to our continuing operations attributable to our proved and unproved properties and other items of $43.5 million which primarily included proved impairments to our Opossum Hollow and Golden Prairie fields of $1.1 million and unproved impairments of $30.0 million related to our Columbia River Basin leasehold, Hingeline leasehold, Haynesville leasehold, Delores River leasehold, Howard Ranch leasehold, and our non-operated Garden Gulch field in the Piceance Basin. Other assets impairments during 2010 resulted from changes to our exploration and development efforts including $6.7 million for the produced water handling facility in Vega and $4.9 million to reduce the Paradox pipeline carrying value to its estimated fair value.

In 2009, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $143.3 million primarily related to our non-operated Garden Gulch field in the Piceance Basin of $38.6 million, Haynesville Shale of $27.5 million, Columbia River Basin of $21.4 million, Lighthouse Bayou of $14.8 million, proved and unproved impairments in various Gulf Coast fields of $18.5 million, Vega surface land of $10.5 million, proved and unproved impairments in various non-Piceance fields of $5.4 million, and pipe and tubular inventory of $4.3 million. The impairments resulted primarily from the significant decline in commodity pricing for most of 2009 causing downward revisions to proved reserves which led to impairments. Lastly, we recorded an impairment of $1.9 million to reduce the Paradox pipeline carrying value to its estimated fair value.

In 2008, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $277.7 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas of $192.5 million, Paradox field in Utah of $30.5 million, Howard Ranch and Bull Canyon fields in the Rockies of $4.1 million, Utah Hingeline of $40.8 million and our offshore California field of $9.8 million. The impairments were primarily due to the significant decline in commodity pricing during the fourth quarter of 2008. In addition, we recorded impairments to our Paradox pipeline of $21.5 million, certain DHS rigs of $21.6 million and we wrote off DHS's goodwill of $7.7 million.

We incurred dry hole costs on several less significant properties that totaled approximately $86,000 for the year ended December 31, 2010. We recorded dry hole costs totaling $33.6 million for the year ended December 31, 2009 related primarily to our Columbia River Basin exploratory well in Washington. During 2008, we recorded dry hole costs totaling $111.9 million for nine wells in Utah, four wells in Texas, two wells in Wyoming, two wells in California, one well in Louisiana and a non-operated project in the Columbia River Basin.

At December 31, 2009, we had no exploratory work in process. During 2009, we declared our exploratory Columbia River Basin well a dry hole and accordingly, at December 31, 2009, we had no remaining capitalized exploratory well costs. During 2010, we spud a deep exploratory test well in the Vega area to evaluate resource potential on our

Piceance leasehold below the currently productive Williams Fork section. Completion activities on the well are currently in progress.

Lower natural gas and oil prices have negatively impacted, and could continue to negatively impact, our ability to borrow.

Our senior credit facility limits our borrowings to the lesser of the borrowing base and the total commitments. The borrowing base is determined periodically at the discretion of the banks and is based in part on natural gas and oil prices. Additionally, the indenture governing our 7% senior notes contains covenants imposing limitations on our ability to incur indebtedness in addition to that incurred under our senior credit facility. These agreements limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on our adjusted consolidated net tangible assets (as defined in our lending agreements), which is determined using discounted future net revenues from proved natural gas and oil reserves as of the end of each year. The second alternative is based on the ratio of our consolidated EBITDAX (as defined in the relevant indentures) to our adjusted consolidated interest expense over a trailing twelve-month period. Currently, we are permitted to incur additional indebtedness under both debt incurrence tests; however, our current borrowing base limits the amount of borrowing permitted under our credit facility. Lower natural gas and oil prices in the future could reduce our consolidated EBITDAX, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness. Lower natural gas and oil prices could also further reduce the borrowing base under our revolving bank credit facility, and if such borrowing base were reduced below the amount of borrowings outstanding, we would be required to repay an amount of borrowings such that outstanding borrowings do not exceed the borrowing base.

The exploration, development and operation of oil and gas properties involve substantial risks that may result in a total loss of investment.

The business of exploring for and, to a lesser extent, developing and operating oil and gas properties involves a high degree of business and financial risk, and thus a substantial risk of investment loss that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- availability of capital;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse changes in prices;
- adverse weather conditions;
- title problems;
- shortages in experienced labor; and
- increases in the cost of, or shortages or delays in the delivery of equipment.

The cost to develop our proved reserves as of December 31, 2010 is estimated to be approximately $18.9 million. In the current financing environment and given the significant capital we have raised in recent years, we expect it to be more difficult to obtain that capital than in the past and it may limit our success in attracting joint venture or industry partners to develop our reserves. We may drill wells that are unproductive or, although productive, do not produce oil and/or natural gas in economic quantities. Acquisition and completion decisions generally are based on subjective judgments and assumptions that are speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, a successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational, or market-related factors, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions may substantially delay or prevent completion of any well or otherwise prevent a property or well from being profitable. A productive well may become uneconomic in the event water or other deleterious substances are encountered which impair or prevent the production of oil and/or natural gas from the well, or in the event of lower than expected commodity prices. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances.

The marketability of our production depends mostly upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities, which are owned by third parties.

The marketability of our production depends upon the availability, operation and capacity of gas gathering systems, pipelines and processing facilities, which are owned by third parties. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. United States federal, state and foreign regulation of oil and gas production and transportation, tax and energy policies, damage to or destruction of pipelines, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors changed dramatically, the financial impact on us could be substantial. The availability of markets and the volatility of product prices are beyond our control and represent a significant risk.

Prices may be affected by regional factors.

The prices to be received for the natural gas production from our Rocky Mountain Region properties, where we are conducting a substantial portion of our development activities, will be determined to a significant extent by factors affecting the regional supply of and demand for natural gas, including the adequacy of the pipeline and processing infrastructure in the region to process, and transport, our production and that of other producers. Those factors result in basis differentials between the published indices generally used to establish the price received for regional natural gas production and the actual (frequently lower) price we receive for our production.

Our industry experiences numerous operating hazards that could result in substantial losses.

The exploration, development and operation of oil and gas properties also involve a variety of operating risks including the risk of fire, explosions, blowouts, cratering, pipe failure, abnormally pressured formations, natural disasters, acts of terrorism or vandalism, and environmental hazards, including oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. These industry-operating risks can result in injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations which could result in substantial losses.

We maintain insurance against some, but not all, of the risks described above. Such insurance may not be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. Terrorist attacks and certain potential natural disasters may change our ability to obtain adequate insurance coverage. The occurrence of a significant event that is not fully insured or indemnified against could materially and adversely affect our financial condition and operations.

We may be unable to compete effectively with larger companies, which could have a material adverse effect on our business, results of operations, and financial condition.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources than us. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial resources permit. In addition, these companies may have a greater ability to continue exploration and development activities during periods of low oil and natural gas market prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse effect on our business, results of operations, and financial condition.

We depend on key personnel.

We currently have three employees that serve in executive management roles. In particular, Carl E. Lakey is our President and Chief Executive Officer, Kevin K. Nanke is our Treasurer and Chief Financial Officer, and Stanley F. Freedman is our Executive Vice President, General Counsel and Secretary. The loss of any one of these employees could severely harm our business. We do not have key man insurance on the lives of any of these individuals. Furthermore, competition for experienced personnel is intense. If we cannot retain our current personnel or attract additional experienced personnel, our ability to compete could be adversely affected.

We are exposed to additional risks through our drilling business, DHS.

We currently have a 49.8% ownership interest in and management control of DHS, a drilling business. The operations of that entity are subject to many additional hazards that are inherent to the drilling business, including, for example, blowouts, cratering, fires, explosions, loss of well control, loss of hole, damaged or lost drill strings and damage or loss from inclement weather. No assurance can be given that the insurance coverage maintained by that entity will be sufficient to protect it against liability for all consequences of well disasters, personal injury, extensive fire damage or damage to the environment. No assurance can be given that the drilling business will be able to maintain adequate insurance in the future at rates it considers reasonable or that any particular types of coverage will be available. The occurrence of events, including any of the above-mentioned risks and hazards that are not fully insured, could subject the drilling business to significant liability. It is also possible that we might sustain significant losses through the operation of the drilling business even if none of such events occurs.

DHS has significant near-term liquidity issues. There is a significant risk that DHS will continue to not be able to meet its debt covenants under its credit facility.

DHS currently has only 10 of its 18 rigs in operation and expects to continue to incur liquidity pressures during 2011 based on its current cash flows and level of indebtedness. DHS is now highly leveraged relative to its cash flow and its senior lender, Lehman Commercial Paper, Inc., ("LCPI") has filed for bankruptcy protection. DHS is in the process of attempting to procure amended financing terms from LCPI or alternative financing from other sources with more favorable debt terms, but there can be no assurance that its efforts will be successful. At December 31, 2010, DHS owed $69.6 million under its credit facility and was not in compliance with its financial covenants. DHS did not pay its scheduled principal and interest payment on January 1, 2011 and subsequently entered into a Forbearance Agreement that currently expires on March 25, 2011. In the event that DHS is not successful in obtaining alternative financing or making satisfactory arrangements with the LCPI bankruptcy trustee, it is likely that DHS will continue to be in default of its debt covenants under its credit facility unless and until market conditions improve significantly. In such event and upon expiration of the Forbearance Agreement, all of the amounts due under the credit facility would become immediately due and payable if LCPI exercised its rights under the terms of the credit facility. All of the DHS rigs are pledged as collateral for the credit facility, and would be subject to foreclosure in the event of a default under the credit facility. The DHS credit facility is non-recourse to Delta. At December 31, 2010, Delta had a net credit investment of approximately $2.8 million in DHS. Subsequent to year-end, the Board of Directors of DHS engaged transaction advisors to commence a strategic alternatives process, focused on a sale of the company or substantially all of its assets. There can be no assurance that the terms offered by a potential buyer, if any, will be acceptable to the DHS shareholders. Additionally, the consummation of certain transactions are subject to the approval of DHS's senior lender and the proceeds received will be required to be used to pay down amounts outstanding under its DHS credit facility.

Hedging transactions may limit our potential gains or cause us to lose money.

In order to manage our exposure to price risks in the marketing of oil and gas, we periodically enter into oil and gas price hedging arrangements, typically fixed price swaps. While intended to reduce the effects of volatile oil and gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production is substantially less than expected;
- the counterparties to our futures contracts fail to perform under the contracts; or
- a sudden, unexpected event materially impacts gas or oil prices.

The total gains (losses) on derivative instruments recognized in our statements of operations were $18.1 million, ($28.1 million), and $21.7 million for the years ended December 31, 2010, 2009 and 2008, respectively. As of February 28, 2011, we had derivative contracts in place that hedge approximately 225 MBbls of oil, 5.7 Bbtu of natural gas and 13.2 MMgl of natural gas liquids. For 2012 we have approximately 181 MBbls of oil hedged, 4.4 Bbtu of natural gas hedged, and 11.2 MMgl of natural gas liquids hedged. For 2013 we have 145 MBbls of oil hedged, 3.8 Bbtu of natural gas hedged, and 4.5 MMgl of natural gas liquids hedged.

We may not receive payment for a portion of our future production.

Our revenues are derived principally from uncollateralized sales to customers in the oil and gas industry. The concentration of credit risk in a single industry affects our overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. Although we have not been directly affected, we are aware that some refiners have filed for bankruptcy protection, which has caused the affected producers to not receive payment for the production that was delivered. If economic conditions deteriorate, it is likely that additional, similar situations will occur which will expose us to added risk of not being paid for oil or gas that we deliver. We do not attempt to obtain credit protections such as letters of credit, guarantees or prepayments from our purchasers. We are unable to predict what impact the financial difficulties of any of our purchasers may have on our future results of operations and liquidity.

We have no long-term contracts to sell oil and gas.

We do not have any long-term supply or similar agreements with governments or other authorities or entities for which we act as a producer. We are therefore dependent upon our ability to sell oil and gas at the prevailing wellhead market price. There can be no assurance that purchasers will be available or that the prices they are willing to pay will remain stable and not decline.

Terrorist attacks aimed at our facilities could adversely affect our business.

The United States has been the target of terrorist attacks of unprecedented scale. The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any terrorist attack at our facilities, or those of our purchasers, could have a material adverse effect on our business.

We own properties in the Gulf Coast Region that could be susceptible to damage by severe weather.

Certain areas in and near the Gulf of Mexico experience hurricanes and other extreme weather conditions on a relatively frequent basis. Some of our properties in the Gulf Coast Region are located in areas that could cause them to be susceptible to damage by these storms. Damage caused by high winds and flooding could potentially cause us to curtail operations and/or exploration and development activities on such properties for significant periods of time until damage can be repaired. Moreover, even if our properties are not directly damaged by such storms, we may experience disruptions in our ability to sell our production due to damage to pipelines, roads and other transportation and refining facilities in the area.

We may incur substantial costs to comply with the various federal, state and local laws and regulations that affect our oil and gas operations.

We are affected significantly by a substantial amount of governmental regulations that increase costs related to the drilling of wells and the transportation and processing of oil and gas. It is possible that the number and extent of these regulations, and the costs to comply with them, will increase significantly in the future. In Colorado, for example, significant new governmental regulations have been adopted that are primarily driven by concerns about wildlife and the environment. These government regulatory requirements complicate our plans for development and may result in substantial costs that are not possible to pass through to our customers and which could impact the profitability of our Colorado operations.

Our oil and gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to health and safety, land use, environmental protection or the oil and gas industry generally. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing our regulatory burden. Compliance with such laws and regulations often increases our cost of doing business and, in turn, decreases our profitability. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the incurrence of investigatory or remedial obligations, or issuance of cease and desist orders.

The environmental laws and regulations to which we are subject may:

- require applying for and receiving a permit before drilling commences;

- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

- impose substantial liabilities for pollution resulting from our operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our earnings, results of operations, competitive position or financial condition. Over the years, we have owned or leased numerous properties for oil and gas activities upon which petroleum hydrocarbons or other materials may have been released by us or by predecessor property owners or lessees who were not under our control. Under applicable environmental laws and regulations, including CERCLA, RCRA and analogous state laws, we could be held strictly liable for the removal or remediation of previously released materials or property contamination at such locations regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed.

Our gas drilling and production operations require adequate sources of water to facilitate the fracturing process and the disposal of that water when it flows back to the well-bore. If we are unable to dispose of the water we use or remove at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities could be impaired.

New environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse affect on our operations and financial performance.

Further, we must remove the water that we use to fracture our gas wells when it flows back to the well-bore. Our ability to remove and dispose of water will affect our production and the cost of water treatment and disposal may affect our profitability. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing or disposal of waste, including produced water, drilling fluids and other wastes associated with the exploration, development and production of natural gas.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress has considered legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale formations, as well as tight conventional formations, including many of those that we complete and produce. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. In addition, some states have adopted and others are considering legislation to restrict hydraulic fracturing. Wyoming has adopted legislation requiring the disclosure of hydraulic fracturing chemicals. Further, a Congressional Committee is investigating hydraulic fracturing practices legislation that requires the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, any additional level of regulation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

We are exposed to credit risk as it affects third parties with whom we have contracted.

Third parties with whom we have contracted may lose existing financing or be unable to obtain additional financing necessary to continue their businesses. The inability of a third party to make payments to us for our accounts receivable, or the failure of our third party suppliers to meet our demands because they cannot obtain sufficient credit to continue their operations, may cause us to experience losses and may adversely impact our liquidity and our ability to make our payments when due.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

Changes contained in President Obama's 2012 budget proposal include the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of any legislation as a result of the budget proposal, or any other similar change in U.S. federal income tax law, could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Potential legislative and regulatory actions addressing climate change could increase our costs, reduce our revenue and cash flow from natural gas and oil sales or otherwise alter the way we conduct our business.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere. In December 2009, the EPA issued proposed regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and also could require permits for emitting greenhouse gas from certain stationary sources such as ours. Congress has also been considering various bills that would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases and at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs. As an alternative to reducing emission of greenhouse gases under cap and trade programs, Congress may consider the implementation of a program to tax the emission of carbon dioxide and other greenhouse gases. The net effect of such legislation would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas. Passage of climate change legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA or analogous state agencies that regulate or restrict emissions of greenhouse gases in areas in which we conduct business, could increase the costs of our operations, including new or increased costs to operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas and oil. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have adverse effects on our business, financial position, results of operations and prospects.

Risks Related To Our Stock.

Our largest stockholder has the power to significantly influence the future of our Company.

As of February 28, 2011, our largest stockholder, Tracinda Corporation ("Tracinda"), beneficially owned approximately 93,798,000 shares of our common stock, or approximately 33% of the outstanding shares of our common stock. Pursuant to the Company Stock Purchase Agreement that we entered into with Tracinda on

December 29, 2007, Tracinda has certain rights, including the right to designate a number of members of our Board of Directors proportional to their ownership in the Company, preemptive rights in connection with future equity issuances by us, and consent rights over certain types of actions. Tracinda has designated three out of the eleven members currently comprising our Board of Directors, one of whom serves as our Board Chairman. While Tracinda agreed not to acquire more than 49% of our outstanding common stock until February 20, 2009, there are currently no limitations as to the number of our outstanding shares of common stock that Tracinda Corporation may acquire. Consequently, Tracinda Corporation has the power to significantly influence matters requiring approval by our stockholders, including the election of directors, and the approval of mergers and other significant corporate transactions. The acquisition of 50% or more of our common stock by Tracinda or any other stockholder would require us to repurchase all of our senior notes and convertible notes per the terms of our indentures. This concentration of ownership may make it more difficult for other stockholders to effect substantial changes in our Company and may also have the effect of delaying, preventing or expediting, as the case may be, a change in control of our Company. Tracinda also has the right to sell its Delta stock if it chooses to do so and, as required by the terms of the Company Stock Purchase Agreement, all of its shares are currently registered for resale. In the event that Tracinda sells all or a substantial portion of its Delta shares, it is possible that the market price of our stock could be adversely affected.

Sales of a substantial number of shares of our common stock, or the perception that such sales might occur, could have an adverse effect on the price of our common stock.

As of December 31, 2010, approximately 33% of our common stock was held by Tracinda Corporation. No other investor held more than 5% of our common stock. Sales by Tracinda Corporation of a substantial number of shares of our common stock into the public market, or the perception that such sales might occur, could have an adverse effect on the price of our common stock.

We are not currently in compliance with The NASDAQ Capital Market $1.00 minimum bid price requirement, and failure to regain and maintain compliance with this standard could result in delisting and adversely affect the market price and liquidity of our common stock.

Our common stock is currently traded on The NASDAQ Capital Market under the symbol "DPTR." If we fail to meet any of the continued listing standards of The NASDAQ Capital Market, our common stock will be delisted from The NASDAQ Capital Market. These continued listing standards include specifically enumerated criteria, such as a $1.00 minimum closing bid price. On February 8, 2011, we received a letter from The NASDAQ Stock Market advising us that we did not meet the minimum $1.00 per share bid price requirement for continued inclusion on The NASDAQ Capital Market pursuant to NASDAQ Marketplace Listing Rule 5550(a)(2). The letter stated that we have until August 8, 2011 to regain compliance. To regain compliance with the applicable listing rule, the closing bid price of our common stock must meet or exceed $1.00 per share for a minimum of ten consecutive business days during the 180 day grace period. If this occurs, NASDAQ will provide us with written notification of compliance. If we do not regain compliance by August 8, 2011, NASDAQ will provide written notice that our common stock is subject to delisting. In that event, we may appeal such determination to a hearings panel. There can be no guarantee that we will be able to regain compliance with the Listing Rule. Further, this deficiency notice relates exclusively to our bid price deficiency. We may be delisted during the applicable grace periods for failure to maintain compliance with any other listing requirement which may occur.

If our common stock were to be delisted from The NASDAQ Capital Market, trading of our common stock most likely will be conducted in the over-the-counter market on an electronic bulletin board established for unlisted securities such as the OTC Bulletin Board. Such trading will reduce the market liquidity of our common stock. As a result, an investor would find it more difficult to dispose of, or obtain accurate quotations for the price of, our common stock. If our common stock is delisted from The NASDAQ Capital Market and the trading price remains below $5.00 per share, trading in our common stock might also become subject to the requirements of certain rules promulgated under the Exchange Act which require additional disclosure by broker-dealers in connection with any trade involving a stock defined as a "penny stock" (generally, any equity security not listed on a national securities exchange or quoted on NASDAQ that has a market price of less than $5.00 per share, subject to certain exceptions). Many brokerage firms are reluctant to recommend low-priced stocks to their clients. Moreover, various regulations and policies restrict the ability of shareholders to borrow against or "margin" low-priced stocks, and declines in the stock price below certain levels may trigger unexpected margin calls. Additionally, because brokers' commissions on low-priced stocks generally represent a higher percentage of the stock price than commissions on higher priced stocks, the current price of the common stock can result in an individual shareholder paying transaction costs that represent a higher percentage of total share value than would be the case if our share price were higher. This factor may also limit the willingness of institutions to purchase our common stock. Finally, the additional burdens imposed upon broker-dealers by these requirements could discourage broker-dealers from facilitating trades in our common stock, which could severely limit the market liquidity of the stock and the ability of investors to trade our common stock.

We may issue shares of preferred stock with greater rights than our common stock.

Our certificate of incorporation authorizes our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from our stockholders. Any preferred stock that is issued may rank ahead of our common stock, in terms of dividends, liquidation rights and voting rights.

There may be future dilution of our common stock.

To the extent options to purchase common stock under our employee and director stock option plans, outstanding warrants to purchase common stock are exercised or the price vesting triggers under the performance shares granted to our executive officers are satisfied, or additional shares of restricted stock are issued to our employees, holders of our common stock will experience dilution. As of December 31, 2010, we had outstanding options to purchase 1,608,000 shares of common stock at a weighted average exercise price of $7.26. Further, if we sell additional equity or convertible debt securities, such sales could result in increased dilution to our existing stockholders and cause the price of our outstanding securities to decline.

We do not expect to pay dividends on our common stock.

We have never paid dividends with respect to our common stock, and we do not expect to pay any dividends, in cash or otherwise, in the foreseeable future. We intend to retain any earnings for use in our business. In addition, the credit agreement relating to our credit facility prohibits us from paying any dividends and the indenture governing our senior notes restricts our ability to pay dividends. In the future, we may agree to further restrictions.

The common stock is an unsecured equity interest in our Company.

As an equity interest, our common stock is not secured by any of our assets. Therefore, in the event we are liquidated, the holders of the common stock will receive a distribution only after all of our secured and unsecured creditors have been paid in full. There can be no assurance that we will have sufficient assets after paying our secured and unsecured creditors to make any distribution to the holders of the common stock.

Our stockholders do not have cumulative voting rights.

Holders of our common stock are not entitled to accumulate their votes for the election of directors or otherwise. Accordingly, a plurality of holders of our outstanding common stock will be able to elect all of our directors. As of December 31, 2010, our directors and executive officers collectively and beneficially owned, directly or indirectly, approximately 2.5% of our outstanding common stock.

Anti-takeover provisions in our certificate of incorporation, Delaware law and certain of our contracts may have provisions that discourage corporate takeovers and could prevent stockholders from realizing a premium on their investment.

Certain provisions of our certificate of incorporation, the provisions of the Delaware General Corporation Law and certain of our contracts may discourage persons from considering unsolicited tender offers or other unilateral takeover proposals or require that such persons negotiate with our board of directors rather than pursue non-negotiated takeover attempts. These provisions may discourage acquisition proposals or delay or prevent a change in control. As a result, these provisions could have the effect of preventing stockholders from realizing a premium on their investment.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights of those shares, as the board of directors may determine. In addition, our Certificate of Incorporation authorizes a substantial number of shares of common stock in excess of the shares outstanding. These provisions may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

Under our credit facility, a change in control is an event of default. Under the indenture governing our senior notes, upon the occurrence of a change in control, the holders of our senior notes will have the right, subject to certain conditions, to require us to repurchase their notes at a price equal to 101% of their principal amount, plus accrued and unpaid interest to the date of the repurchase.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

Properties.

Piceance Basin

Our core asset and primary area of activity is in the Vega Area of the Piceance Basin in western Colorado. The Williams Fork member of the Mesa Verde formation is the primary producing interval and has been successfully developed throughout the Piceance Basin. The geology of the Piceance Basin is characterized as highly consistent and predictable over large areas, which generally equates to reliable timing and cost expectations during drilling and completion activities, as well as minimal well-to-well variance in production and reserves when completed with the same methodology.

Vega Area. Since 2005 we have dedicated significant financial capital and human resources to the development of our Vega Unit and surrounding leasehold in Mesa County, Colorado, which in combination is referred to as the Vega Area. The Vega Area is comprised of the Vega Unit, the Buzzard Creek Unit, the North Vega leasehold, and the North Buzzard Creek leasehold. Our working interest in the Vega Area varies between 95-100%. In 2008, we acquired an additional 17,300 net acres, which increased our position to approximately 22,375 net acres, which has over 1,900 net drilling locations based on 10-acre spacing. During fiscal 2008, we increased proved reserves in the Vega Area over 295% to 719.9 Bcfe and increased production from approximately 25.0 Mmcf/d at the beginning of the year to approximately 48.0 Mmcf/d at the end of 2008. However, during 2009, as a result of the combined effect of lower gas prices through the year and the new SEC reserve pricing rules and our limited capital development plan, proved reserves decreased to 84.7 Bcfe. At December 31, 2010, proved reserves in the Vega Area totaled 112.6 Bcfe. Net production in the Vega Area currently exceeds 30.0 Mmcfe/d. We ended 2010 with 190 wells producing. Despite our large inventory of over 1,900 drilling locations and efficient reserve growth, we decreased our drilling program from four rigs to one rig at year end 2008, and further to zero rigs in 2009 and 2010, primarily due to the decrease in natural gas prices and liquidity concerns. Since 2005 we have experienced significant reductions in drill time, and drilling and completion costs. We reinitiated completion activities in the latter half of 2010 on previously drilled wells. These recently completed wells utilized a larger fracture stimulation design, called "generation four" or "Gen IV", which has proven to increase the initial production and recoverable reserves per well over our prior completion designs. Additionally, we drilled a well in the Vega Area to test the sections that are located deeper than the Williams Fork section. We began completion activities on this deep test well subsequent to year end. We also began drilling another well, which will target the section immediately beneath the Williams Fork section. Our drilling and completion capital budget for the Vega Area for 2011 has not yet been determined beyond the exploratory test wells, lease preservation well, and drilled but not completed wells described elsewhere, pending the results of the exploratory test wells.

Non-Operated Assets

Because of our continued focus in the Piceance Basin, we do not anticipate significant capital expenditures in 2011 on any of the properties described below. Collectively, as of December 31, 2010, these properties comprised 21.6 Bcfe, or 16% of our proved reserves.

South Piceance. We have a 5% working interest in 153 producing wells in the southern region of the Piceance Basin. We also have a 5% working interest in an additional 75 wells remaining to be drilled, but will not incur any capital expenditures on these wells in accordance with the carry provisions of the February 2008 agreement with Encana.

Cowboy Field. Our leasehold in the Denver Julesburg ("DJ") Basin of northeastern Colorado and southeastern Wyoming focuses on the "J" sand formation at depths of between 7,000 feet and 8,000 feet. We have approximately 305 net acres with an average 47% working interest in the proved reserves of this field.

Newton Field. The Newton Field is located in Newton County, Texas where we have an interest in approximately 1,914 net acres with an average 50% working interest in the proved reserves of this field.

Midway Loop Field. The Midway Loop Field is located in Polk and Tyler Counties, Texas. We have an interest in approximately 2,470 net acres, with an average 32% working interest in the proved reserves of this field.

Caballos Creek / Opossum Hollow. The leasehold is located in Atascosa and McMullen Counties, Texas. We have an interest in approximately 392 net acres, with an average 48% working interest in the proved reserves of this field.

Point Arguello and Rocky Point Units. We own the equivalent of a 6.07% gross working interest in the Point Arguello Unit and related facilities located Offshore California in the Santa Barbara Channel. Within this unit there are three producing platforms (Hidalgo, Harvest and Hermosa). We also own a 6.25% working interest in the development of the east half of OCS Block 451 in the Rocky Point Unit.

Exploration/Undeveloped Assets

While we have significant undeveloped acreage positions in several basins and exploratory areas as listed below, we intend to dedicate all of our efforts and capital to the development of the Vega Area. Therefore, we have no planned capital expenditures in these areas for 2011. As of December 31, 2010 these areas do not contain any of our proved reserves.

Paradox Basin. In the Paradox Basin of southwest Colorado and southeast Utah we have a 66.1% working interest in approximately 17,599 net acres. In 2007 and 2008 we drilled a total of nine wells in the Paradox Basin. The results of these wells were mixed and in the latter half of 2008 we ceased all drilling and completion activity in the Paradox Basin after determining that the results were uneconomic.

Central Utah Hingeline. The central Utah Hingeline Region is an overthrust belt located in central Utah. We have an average 60.4% working interest in approximately 100,000 net acres. From 2006 through 2008 we drilled three exploration wells. All three wells were plugged and abandoned as dry holes.

Columbia River Basin. The Columbia River Basin is located in southeast Washington and northeast Oregon. During 2009, we drilled the Gray 31-23 well. The well did not reach the targeted Roslyn formation and was plugged and abandoned. We have an interest in approximately 184,000 net acres in the basin, all of which are undeveloped.

Internal Controls Over Reserve Estimates, Technical Qualifications and Technologies Used

Our policies regarding internal controls over reserve estimates requires reserves to be in compliance with the SEC definitions and guidance and for reserves to be prepared by an independent third party reserve engineering firm under the supervision of our Corporate Engineering Manager. Qualified petroleum engineers in our Denver office provide to our third party reserves engineers reserves estimate preparation material such as property interests, production, current costs of operation and development, current prices for production, geoscience and engineering data, and other information. This information is reviewed by knowledgeable members of our reserve engineering department to ensure accuracy and completeness of the data prior to submission to our third party reserve engineering firm. In each of the years 2010, 2009 and 2008, we retained Ralph E. Davis Associates, Inc. ("RDAI"), independent, third-party reserve engineers, to prepare our estimates of proved reserves. A letter which identifies the professional qualifications of the individual at RDAI who was responsible for overseeing the preparation of our reserve estimates as of December 31, 2010 has been filed as a part of Exhibit 99.1 to this report.

The SEC's new rules expanded the technologies that a company can use to establish reserves. The SEC now allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. A variety of methodologies were used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, analog type curve analysis, volumetrics, material balance, pressure transient analysis, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

Reserves Reported to Other Agencies

We did not file any reports during the year ended December 31, 2010 with any federal authority or agency other than the SEC with respect to our estimates of oil and natural gas reserves.

DHS Drilling Company Rigs

We own 49.8% of DHS, which as of December 31, 2010 owned 18 rigs with depth ratings of 10,000 to 25,000 feet. The following table shows property information and location for the DHS rigs.

	Operating Region	Year Built or Refurbished	Horsepower	Depth Capacity
Rig No. 1	ND	2005	1,500	18,000
Rig No. 4	MT	2007	700	11,000
Rig No. 5	NV	2005	700	13,000
Rig No. 6	CO	2005	700	12,000
Rig No. 8	CO	2005	800	12,500
Rig No. 9	ND	2006	1,000	15,000
Rig No. 10	ND	2006	1,000	15,000
Rig No. 11	NV	2006	750	11,000
Rig No. 12	ND	2006	1,000	15,000
Rig No. 14	WY	2006	800	12,500
Rig No. 15	WY	2006	700	10,000
Rig No. 16	WY	2006	700	10,000
Rig No. 17	MT	2006	1,000	12,500
Rig No. 18	WY	2007	700	10,500
Rig No. 19	WY	2008	700	12,500
Rig No. 20	NE	2008	1,000	12,500
Rig No. 23	TX	2008	2,000	25,000
Rig No. 24	TX	2008	1,300	12,500

Office Facilities

Our offices are located at 370 Seventeenth Street, Suite 4300, Denver, Colorado 80202. We lease approximately 49,000 square feet of office space. Our current lease payments are approximately $97,900 per month and our lease expires in December 2014.

Production

During the years ended December 31, 2010, 2009 and 2008, we have not had, nor do we now have, any long-term supply or similar agreements with governments or authorities under which we acted as producer.

Impairment of Long Lived Assets

On a quarterly basis, we compare our historical cost basis of each proved developed and undeveloped oil and gas property to its expected future undiscounted net cash flow from each property (on a field by field basis). Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions and projections. If the expected future net cash flows exceed the carrying value of the property, no impairment is recognized. If the carrying value of the property exceeds the expected future cash flows, an impairment exists and is measured by the excess of the carrying value over the estimated fair value of the asset. As a result of this assessment, during the year ended December 31, 2010, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties and other items of $43.5 million which primarily included proved impairments to our Opossum Hollow and Golden Prairie fields of $1.1 million and unproved impairments of $30.0 million related to our Columbia River Basin leasehold, Hingeline leasehold, Haynesville leasehold, Delores River leasehold, Howard Ranch leasehold, and our non-operated Garden Gulch field in the Piceance Basin. Other impairments primarily included $6.7 million for the produced water handling facility in Vega and $4.9 million to reduce the Paradox pipeline carrying value to its estimated fair value.

In 2009, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $143.3 million primarily related to our non-operated Garden Gulch field in the

Piceance Basin of $38.6 million, Haynesville Shale of $27.5 million, Columbia River Basin of $21.4 million, Lighthouse Bayou of $14.8 million, proved and unproved impairments in various Gulf Coast fields of $18.5 million, Vega surface land of $10.5 million, proved and unproved impairments in various Rockies fields of $5.4 million, pipe and tubular inventory of $4.3 million, and Paradox pipeline of $1.9 million.

In 2008, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $277.7 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas of $192.5 million, Paradox field in Utah of $30.5 million, Howard Ranch and Bull Canyon fields in the Rockies of $4.1 million, Hingeline field in Utah of $40.8 million and our offshore California field of $9.8 million. The impairments resulted primarily from the significant decline in commodity pricing during the fourth quarter of 2008. In addition, we recorded impairments to our Paradox pipeline of $21.5 million, certain DHS rigs of $21.6 million and we wrote off DHS goodwill of $7.7 million.

Production Volumes, Unit Prices and Costs

The following table sets forth certain information regarding our volumes of production sold and average prices received associated with our production and sales of natural gas and crude oil for the years ended December 31, 2010, 2009, and 2008.

	Years Ended December 31,		
	2010	2009	2008
Production volume – Total production (MMcfe)	16,763	22,158	24,908
Production from continuing operations:			
Oil (MBbls)	500	734	950
Natural Gas (MMcf)	11,759	14,319	15,164
Total (MMcfe)	14,759	18,727	20,863
Net average daily production-continuing operations:			
Oil (Bbl)	1,370	2,013	2,602
Natural Gas (Mcf)	32,216	39,230	41,545
Average sales price:			
Oil (per barrel)	$ 70.90	$ 52.45	$ 92.47
Natural Gas (per Mcf)	$ 5.01	$ 3.09	$ 6.92
Hedge gain (loss) (per Mcfe)	$ (0.40)	$ (0.06)	$ 0.88
Lease operating costs - (per Mcfe)	$ 1.66	$ 1.41	$ 1.34

Productive Wells and Acreage

The table below shows, as of December 31, 2010, the approximate number of gross and net producing oil and gas wells by state and their related developed acres owned by us. Calculations include 100% of wells and acreage owned by us and our subsidiaries. Developed acreage consists of acres spaced or assignable to productive wells.

	Oil (1)		Gas (1)		Developed Acres	
Location	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
California (onshore)	-	-	1	-	1,057	157
California (offshore)	34	2.1	-	-	2,422	269
Colorado	-	-	343	196.0	1,920	1,866
New Mexico	-	-	1	0.1	240	13
Oklahoma	-	-	-	-	560	110
Texas	51	13.0	25	4.1	14,550	4,047
Utah	-	-	1	0.3	40	28
Wyoming	16	6.9	-	-	640	285
Total	101	22.0	371	200.5	21,429	6,775

(1) Some of the wells classified as "oil" wells also produce minor amounts of natural gas. Likewise, some of the wells classified as "gas" wells also produce minor amounts of oil.

(2) A "gross well" or "gross acre" is a well or acre in which a working interest is held. The number of gross wells or acres is the total number of wells or acres in which a working interest is owned.

(3) A "net well" or "net acre" is deemed to exist when the sum of fractional ownership interests in gross wells or acres equals one. The number of net wells or net acres is the sum of the fractional working interests owned in gross wells or gross acres expressed as whole numbers and fractions thereof.

Undeveloped Acreage

At December 31, 2010, we held undeveloped acreage by state as set forth below:

	Undeveloped Acres (1)(2)	
Location	Gross	Net
Colorado	36,701	30,384
Louisiana	220	193
Oregon	122,289	13,849
Texas	9,139	5,418
Utah	216,451	135,006
Washington	571,034	170,458
Wyoming	680	220
Total	956,514	355,528

(1) Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether such acreage contains proved reserves.
(2) There are no material near-term lease expirations for which the carrying value at December 31, 2010 has not already been impaired in consideration of these expirations or capital budgeted to convert acreage to HBP.

Drilling Activity

During the years indicated, we drilled or participated in the drilling of the following productive and nonproductive exploratory and development wells:

	Years Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells (2):						
Productive:						
Oil	-	-	-	-	1	1.00
Gas	-	-	-	-	1	0.70
Nonproductive	-	-	1	0.50	19	14.01
Total	-	-	**1**	**0.50**	**21**	**15.71**
Development Wells (1):						
Productive:						
Oil	1	1.00	-	-	7	5.40
Gas	66	16.10	113	32.89	141	82.37
Nonproductive	1	0.25	-	-	-	-
Total	**68**	**17.35**	**113**	**32.89**	**148**	**87.77**
Total Wells (1):						
Productive:						
Oil	1	1.00	-	-	8	6.40
Gas	66	16.10	113	32.89	142	83.07
Nonproductive	1	0.25	1	0.50	19	14.01
Total Wells	**68**	**17.35**	**114**	**33.39**	**169**	**103.48**

(1) Does not include wells in which we had only a royalty interest.
(2) Does not include exploratory wells in progress.

Present Drilling Activity

At December 31, 2010, we had five development wells in the Vega area which had been drilled but not yet completed and one exploratory well in progress. Subsequent to year-end, an additional exploratory well was spud in the Vega Area and is currently in progress. We are unable to accurately predict our anticipated capital expenditures for the full year of 2011, primarily due to the uncertainty relating to results from our in-progress exploratory efforts in the Piceance Basin and sources of capital sufficient to complete our desired level of drilling activity. We expect to announce our 2011 drilling plans once our well results have been evaluated.

Item 3. Legal Proceedings

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of our business. As of the date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows, except as follows:

During the fourth quarter 2010, we were engaged in an arbitration with 212 Resources Corporation ("212") that was filed with the American Arbitration Association on October 27, 2009. The matter was set for arbitration on January 24, 2011, but was ultimately settled pursuant to a final Settlement Agreement executed by the parties on January 25, 2011, which required us to pay $1.5 million to 212 in consideration of mutual releases of claims and the termination of the underlying agreement.

Our indirect, 49.8% owned affiliate DHS and certain of its employees, among others, have been notified by the Office of the Inspector General, Office of Investigations, of the Export-Import Bank of the United States, and the U.S. Department of Justice, that they are the subject of an investigation in connection with a loan guarantee sought from the Export-Import Bank in the first quarter of 2010 of a loan from a Mexican bank sought by a DHS customer in Mexico. DHS has cooperated and will continue to cooperate with the investigation, which is currently in its initial stages. This investigation is subject to uncertainties, and, as such, DHS is unable to estimate the nature of any possible liability that may result.

We formerly owned a 2.41934% working interest in OCS Lease 320 in the Sword Unit, Offshore California, and Amber formerly owned a 0.97953% working interest in the same lease. Lease 320 was conveyed back to the United States at the conclusion of the Amber litigation when the courts determined that the government had breached that lease (among others) and was liable to the working interest owners for damages; however, the government now contends that the former working interest owners are still obligated to permanently plug and abandon an exploratory well that was drilled on the lease and to clear the well site. The former operator of the lease has commenced litigation against the United States seeking a declaratory judgment that the former working interest owners are not responsible for these costs as a result of the government's breach of the lease. It is currently unknown whether or not the litigation will be successful, or what the costs of decommissioning the well would be if the former working interest owners are ultimately held liable.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2010.

Item 4A. Directors and Executive Officers

Our executive officers and members of our Board of Directors, and their respective ages, are as follows:

Name	Age	Positions	Period of Service
Carl E. Lakey	49	President, Chief Executive Officer and Director	July 2010 to Present
Kevin K. Nanke	46	Treasurer and Chief Financial Officer	December 1999 to Present
Stanley F. Freedman	62	Executive Vice President, General Counsel and Secretary	January 2006 to Present
Hank Brown	71	Director	June 2007 to Present
Kevin R. Collins	54	Director	March 2005 to Present
Jerrie F. Eckelberger	66	Director	September 1996 to Present
Jean-Michel Fonck	69	Director	May 2009 to Present
Aleron H. Larson, Jr.	65	Director	May 1987 to Present
Russell S. Lewis	56	Director	June 2002 to Present
Anthony Mandekic	69	Director	May 2009 to Present
James J. Murren	49	Director	February 2008 to Present
Jordan R. Smith	76	Director	October 2004 to Present
Daniel J. Taylor	54	Chairman of the Board and Director	February 2008 to Present

The following is biographical information as to the business experience of each of our current executive officers and directors.

Executive Officers

Carl E. Lakey, President, Chief Executive Officer and Director, joined Delta in April 2007 as Senior Vice President of Operations prior to spending six years managing operations for El Paso's Western Onshore Division and sixteen years at ExxonMobil in various operational and technical positions. He received a Bachelor of Science degree in Petroleum Engineering from Colorado School of Mines in 1985.

Kevin K. Nanke, Treasurer and Chief Financial Officer, joined Delta in April 1995 as our Controller and has served as the Treasurer and Chief Financial Officer of Delta and Amber Resources since 1999. Since April 1, 2005 he has also served as Chief Financial Officer, Treasurer and Director of DHS. Since 1989, he has been involved in public and private accounting with the oil and gas industry. Mr. Nanke received a Bachelor of Arts degree in Accounting from the University of Northern Iowa in 1989. Prior to working with Delta, he was employed by KPMG LLP. He is a member of the Colorado Society of CPA's and the Council of Petroleum Accounting Society.

Stanley F. ("Ted") Freedman has served as Executive Vice President, General Counsel and Secretary since January 1, 2006 and has also served in those same capacities for DHS since that same date. He also serves as Executive Vice President and Secretary of Amber Resources and formerly as a director of Direct Petroleum Exploration, Inc., a privately-held oil and gas company with projects in Morocco, Bulgaria, Russia and southeastern Colorado. He graduated from the University of Wyoming with a Bachelor of Arts degree in 1970 and a Juris Doctor degree in 1975. From 1975 to 1978, Mr. Freedman was a staff attorney with the United States Securities and Exchange Commission. From 1978 to December 31, 2005, he was engaged in the private practice of law, and was a shareholder and director of the law firm of Krys Boyle, P.C. in Denver, Colorado.

<u>Board of Directors</u>

Daniel J. Taylor has been an executive of Tracinda Corporation since February 2007 and has served as a Director of MGM Resorts International since March 2007. Mr. Taylor does not have a specific title at Tracinda but his primary responsibilities include assisting with the management of Tracinda's investments. He was initially employed by Tracinda from May 1991 until July 1997, and has been employed in his current position at Tracinda since February 2007. During the interim period he was employed by Metro-Goldwyn-Mayer Inc., a then public corporation ("MGM"), first as Executive Vice President-Finance, then as Chief Financial Officer from August 1997 to April 2005, at which time MGM was sold. He then served as President of MGM until January 2006. Mr. Taylor received a Bachelor of Science degree in Business Administration with an emphasis in Accounting from Central Michigan University in 1978.

Hank Brown has served as the Senior Counsel to the law firm of Brownstein Hyatt Farber Schreck P.C. since June 1, 2008 and as a member of that firm's Government Relations and Natural Resources groups. He served as the President of the University of Colorado from August 2005 to March 2008. Prior to joining CU, he was President and CEO of the Daniels Fund and served as the President of the University of Northern Colorado from 1998 to 2002. He served Colorado in the United States Senate (elected in 1990) and served five consecutive terms in the U.S. House representing Colorado's 4th Congressional District (1980-1988). He also served in the Colorado Senate from 1972 to 1976. Mr. Brown was a Vice President of Monfort of Colorado from 1969 to 1980. He is both an attorney and a C.P.A. He earned a Bachelor's degree in Accounting from the University of Colorado in 1961 and received his Juris Doctorate degree from the University of Colorado Law School in 1969. While in Washington, D.C., Mr. Brown earned a Master of Law degree in 1986 from George Washington University.

Kevin R. Collins currently serves as Executive Vice President and Chief Financial Officer of Bear Tracker Energy, a position he has held since July 1, 2010. Prior to his current position, Mr. Collins served as President and Chief Executive Officer of Evergreen Energy, Inc. from September 2006 until his retirement on June 1, 2009. He also served on Evergreen's Board of Directors until he resigned effective July 1, 2009. Prior to that, he served as Evergreen's Executive Vice President - Finance and Strategy from September 2005 to September 2006, and acting Chief Financial Officer from November 2005 until March 31, 2006. From 1995 until 2004, Mr. Collins was an executive officer of Evergreen Resources, Inc., serving as Executive Vice President and Chief Financial Officer until Evergreen Resources merged with Pioneer Natural Resources Co. in September 2004. Mr. Collins became a Certified Public Accountant in 1983 and has over 13 years' public accounting experience. He has served as Vice President and a board member of the Colorado Oil and Gas Association, President of the Denver Chapter of the Institute of Management Accountants, and board member and Chairman of the Finance Committee of the Independent Petroleum Association of Mountain States. Mr. Collins received his Bachelor of Science degree in Business Administration and Accounting from the University of Arizona.

Jerrie F. Eckelberger is an investor, real estate developer and attorney who has practiced law in the State of Colorado since 1971. He graduated from Northwestern University with a Bachelor of Arts degree in 1966 and received his Juris Doctor degree in 1971 from the University of Colorado School of Law. From 1972 to 1975, Mr. Eckelberger was a staff attorney with the Eighteenth Judicial District Attorney's Office in Colorado. From 1975 to the present, Mr. Eckelberger has been engaged in the private practice of law in the Denver area. Mr. Eckelberger previously served as an officer, director and corporate counsel for Roxborough Development Corporation. Since March, 1996, Mr. Eckelberger has engaged in the investment and development of Colorado real estate through several private companies in which he is a principal.

Jean-Michel Fonck is President of Geopartners SAS, a service company for petroleum studies located in France, and is consulting with the firm of JMF-Conseil SARL to various oil companies since 2001. Mr. Fonck was previously employed by TOTAL SA ("TOTAL"), serving in various capacities there from 1968 until 2000. During his tenure at TOTAL, he worked in Paris in mathematical applications to geology and exploration venture appraisals, in Indonesia as chief geologist, in Argentina and Egypt as exploration manager and in Paris again as division manager for Exploration New Ventures and International Exploration Coordination. In 1991, Mr. Fonck became President and CEO of the TOTAL exploration and production branch in Houston, and then returned to Paris in 1994 to serve as Vice President of Exploration and Reservoir Evaluation for the TOTAL group. Mr. Fonck graduated from Ecole des Mines (Nancy) in 1963.

Aleron H. Larson, Jr. has operated as an independent in the oil and gas industry individually and through public and private ventures since 1978. Mr. Larson served as Chairman of the Board, Secretary and Director of Delta, as well as Amber Resources, until his retirement on July 1, 2005, at which time he resigned as Chairman of the Board and as an executive officer of the Company. He ceased to be an officer or director of Amber Resources on January 3, 2006. Mr. Larson practiced law in Breckenridge, Colorado from 1971 until 1974. During this time he was a member of a law firm, Larson & Batchellor, engaged primarily in real estate law, land use litigation, land planning and municipal law. In 1974, he formed Larson & Larson, P.C., and was engaged primarily in areas of law relating to securities, real estate, and oil and gas until 1978. Mr. Larson received a Bachelor of Arts degree in Business Administration from the University of Texas at El Paso in 1967 and a Juris Doctor degree from the University of Colorado in 1970.

Russell S. Lewis is Executive Vice President, Strategic Development for VeriSign, Inc., located in Dulles, Virginia, which is the trusted provider of Internet infrastructure services. Mr. Lewis has held a variety of senior executive level roles at VeriSign since 1999, including the GM of VeriSign's Naming and Directory Services Group and Senior Vice President of Corporate Development. Mr. Lewis has been a member of the Board of Directors of Delta Petroleum since June 2002. For the preceding 15 years Mr. Lewis was President and CEO of TransCore, a wireless transportation systems integration company. Prior to that Mr. Lewis managed an oil and gas exploration subsidiary of a publicly traded utility and was Vice President of EF Hutton in its Municipal Finance group. Mr. Lewis also serves on the Board of Directors of Braintech, Inc., NameMedia, Inc., and Dropps, Inc. Mr. Lewis has a Bachelors of Arts degree in Economics from Haverford College and an MBA from the Harvard School of Business.

Anthony Mandekic currently serves as the Secretary/Treasurer of Tracinda Corporation and has held such position since Tracinda Corporation's inception in 1976. Mr. Mandekic also currently serves as Chairman of the Lincy Foundation, a charitable organization founded by Mr. Kerkorian, and has served as its Chief Financial Officer and a Director since 1989. Since May of 2006 he has served as a member of the Board of Directors of MGM Resorts International and as a member of its Executive Committee, Diversity Committee and Compensation Committee. In May of 2007 Mr. Mandekic became Chairman of the MGM Mirage Compensation Committee, and also became a member of the MGM Mirage Corporate Governance and Nominating Committee in 2009. Mr. Mandekic is a graduate of the University of Southern California with a bachelor's degree in Science-Accounting and is a Certified Public Accountant.

James J. Murren is the Chairman and CEO of MGM Resorts International. He is also a member of the Board of Directors and the Executive Committee. Mr. Murren previously served in the following capacities for MGM Resorts: President (1999-2008), Chief Operating Officer (2007-2008), Chief Financial Officer (1998-2007), and Treasurer (2001-2007). Prior to his employment at MGM Resorts International, Mr. Murren spent 14 years on Wall Street as a top-ranked equity analyst and was appointed to Director of Research and Managing Director of Deutsche Bank. Mr. Murren received a Bachelor of Arts degree in Art History and Urban Studies from Trinity College in 1983.

Jordan R. Smith is President of Ramshorn Investments, Inc., a wholly owned subsidiary of Nabors Drilling USA LP that is located in Houston, Texas, where he is responsible for drilling and development projects in a number of producing basins in the United States. He has served in such capacity for more than the past five years. Mr. Smith has served on the Board of the University of Wyoming Foundation and the Board of the Domestic Petroleum Council, and is also Founder and Chairman of the American Junior Golf Association. Mr. Smith received Bachelor and Master degrees in Geology from the University of Wyoming in 1956 and 1957, respectively.

At the present time Messrs. Collins, Eckelberger, Lewis, Smith, and Taylor serve on the Audit Committee; Messrs. Eckelberger, Brown, Collins, Lewis, Mandekic, Murren, and Smith serve on the Compensation Committee; and Messrs. Smith, Collins, Eckelberger, Lewis, Murren, and Taylor serve on the Nominating & Governance Committee.

In conjunction with the February 2008 equity issuance to Tracinda Corporation, and in accordance with the related Company Stock Purchase Agreement, Tracinda designated Messrs. Mandekic, Murren and Taylor to serve on our Board of Directors.

All directors will hold office until the next annual meeting of stockholders. All of our officers will hold office until such time as they resign or are terminated by our Board of Directors. There is no arrangement or understanding among or between any such officers or any persons pursuant to which such officer is to be selected as one of our officers.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities

Market Information; Dividends

Delta's common stock currently trades under the symbol "DPTR" on the NASDAQ Capital Market. The following quotations reflect inter-dealer high and low sales prices, without retail mark-up, mark-down or commission and may not represent actual transactions.

Quarter Ended	High	Low
March 31, 2009	$ 6.17	$ 0.88
June 30, 2009	4.63	1.05
September 30, 2009	4.68	1.46
December 31, 2009	1.85	0.73
March 31, 2010	$ 1.77	$ 1.14
June 30, 2010	1.71	0.86
September 30, 2010	0.87	0.69
December 31, 2010	0.86	0.72

On March 15, 2011, the closing price of our common stock was $0.96. We have not paid dividends on our common stock, and we do not expect to do so in the foreseeable future. Our current debt agreements restrict the payment of dividends.

Approximate Number of Holders of Common Stock

The number of holders of record of our common stock at March 4, 2011 was approximately 1,392 which does not include an estimated 32,266 additional holders whose stock is held in "street name."

Recent Sales of Unregistered Securities

During the year ended December 31, 2010, we did not have any sale of securities in transactions that were not registered under the Securities Act of 1933, as amended ("Securities Act") that have not been reported in a Form 8-K or Form 10-Q.

Issuer Purchases of Equity Securities

The table below provides a summary of our purchases of our own common stock during the three months ended December 31, 2010.

Period	Total Number of Shares (or Units) Purchased (1)	Average Price Paid Per Share (or Unit) (2)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (3)	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (3)
October 1 – October 31, 2010	2,153	$0.80	-	-
November 1 – November 30, 2010	-	-	-	-
December 1 – December 31, 2010	-	-	-	-
Total	2,153	$0.80	-	-

(1) Consists of shares delivered back to us by employees and/or directors to satisfy tax withholding obligations that arise upon the vesting of the stock awards. We, pursuant to our equity compensation plans, give participants the opportunity to turn back to us the number of shares from the award sufficient to satisfy the person's tax withholding obligations that arise upon the termination of restrictions.

(2) The stated price does not include any commission paid.

(3) These sections are not applicable as we have no publicly announced stock repurchase plans.

Item 6. Selected Financial Data

The following selected financial information should be read in conjunction with our financial statements and the accompanying notes.

	Years Ended December 31, 2010	2009	2008	2007	2006
	(In thousands, except per share amounts)				
Total Revenues	$ 146,805	$ 170,203	$ 242,260	$ 183,251	$ 163,184
Loss from continuing operations	$ (121,858)	$ (315,313)	$ (440,447)	$ (103,718)	$ (3,887)
Net Income/(Loss) attributable to Delta common stockholders	$ (182,332)	$ (328,783)	$ (456,064)	$ (149,807)	$ 2,916
Income/(Loss) attributable to Delta common stockholders Per Common Share					
Basic	$ (0.66)	$ (1.56)	$ (4.77)	$ (2.44)	$ 0.06
Diluted	$ (0.66)	$ (1.56)	$ (4.77)	$ (2.44)	$ 0.05
Total Assets	$ 1,024,112	$ 1,457,485	$ 1,894,963	$ 1,110,054	$ 932,614
Total Long-Term debt, including current portion	$ 356,997	$ 460,923	$ 637,473	$ 393,468	$ 367,263
Total Delta Stockholders' Equity	$ 514,447	$ 688,582	$ 762,390	$ 532,855	$ 431,523
Total Non-Controlling Interest	$ (2,852)	$ 8,538	$ 29,104	$ 27,296	$ 27,390
Total Equity	$ 511,595	$ 697,120	$ 791,494	$ 560,151	$ 458,913

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

We are a Denver, Colorado based independent oil and gas company engaged primarily in the exploration for, and the acquisition, development, production, and sale of, natural gas and crude oil. Our core area of operations is the Rocky Mountain Region, which comprises virtually all of our proved reserves, production and long-term growth prospects. We have a significant drilling inventory that consists of proved and unproved locations, the majority of which are located in our Rocky Mountain development projects. At December 31, 2010, we had estimated proved reserves that totaled 134.2 Bcfe, of which 92.2% were proved developed, with a standardized measure of $192.1 million. For the year ended December 31, 2010, we reported total net production of 45.9 Mmcfe per day related to continuing operations.

As of December 31, 2010, our proved reserves were comprised of approximately 122.7 Bcf of natural gas and 1.9

Mmbbls of crude oil, or 91.4% gas on an equivalent basis. Approximately 92% of our proved reserves were located in the Rocky Mountains, 7% in the Gulf Coast and 1% in other locations. We expect that our 2011 drilling efforts and capital expenditures, when announced, will focus primarily on our Piceance Basin assets in the Rockies. As of December 31, 2010, through our position as operator, we controlled approximately 349,697 of our net undeveloped acres, representing approximately 97% of our total acreage position. We retain a high degree of operational control over our asset base, with an average working interest in excess of 85% of our proved reserve properties as of December 31, 2010. This provides us with controlling interests in a multi-year inventory of drilling locations, positioning us for continued reserve and production growth through our drilling operations when commodity prices support such activity.

2010 Developments

- On December 29, 2010, we amended and restated our credit agreement with MBL as more fully described in Note 7, "Long-Term Debt" to the accompanying consolidated financial statements. The MBL Credit Agreement provides for a revolving loan and a term loan each with a maturity date of January 31, 2012. The revolving loan has an initial borrowing base of $30.0 million and the term loan has an initial commitment of $20.0 million subject to a development plan that must be approved by MBL. The MBL Credit Agreement was amended on March 14, 2011 to provide for additional availability under the term loan, among other changes more fully described in Note 20, "Subsequent Events" to the accompanying consolidated financial statements.

- On July 30, 2010, we sold all or a portion of our interest in various non-core assets primarily located in Colorado, Texas, and Wyoming for gross cash proceeds of $130.0 million. In conjunction with the completion of the Wapiti Transaction, we repaid $108.5 million of amounts borrowed under our credit facility, and our borrowing base under the credit facility was reduced to $35.0 million. The proceeds from the Wapiti Transaction allowed us to substantially reduce our outstanding debt and when combined with the post-Wapiti Transaction borrowing base, provided the liquidity necessary to fund our third and fourth quarter 2010 development plan.

- On April 1, 2010, DHS, our 49.8% subsidiary, amended its existing credit facility with Lehman Commercial Paper, Inc. and renegotiated certain terms of the agreement to, among other changes more fully described in Note 7, "Long-Term Debt" to the accompanying financial statements, bring DHS into compliance with the terms of the agreement, amend the principal repayment schedule, adjust the interest rate, and eliminate or amend certain financial covenants. However, DHS was not in compliance with its minimum EBITDA covenant and quarterly capital expenditures limitation as of December 31, 2010. On January 1, 2011, DHS failed to pay its scheduled principal and interest payment and subsequently entered into a forbearance agreement that currently expires on March 25, 2011. Subsequent to year-end, the Board of Directors of DHS engaged transaction advisors to commence a strategic alternatives process, focused on a sale of the company or substantially all of its assets. There can be no assurance that the terms offered by a potential buyer, if any, will be acceptable to the DHS shareholders. Additionally, the consummation of certain transactions are subject to the approval of DHS's senior lender and the proceeds received will be required to be used to pay down amounts outstanding under its DHS credit facility.

- During 2010, we divested of our equity interest in several unconsolidated affiliates. We sold our 5% interest in Collbran Valley Gas Gathering, LLC ("CVGG") for cash proceeds of $3.5 million, our 50% investment interest in Delta Oilfield Tank Company ("DOTC") for cash proceeds of $2.8 million and a note receivable of $2.1 million, and our 50% investment interest in Ally Equipment for cash proceeds of $250,000 and a note receivable of $1.3 million.

2011 Outlook

Based on current commodity prices and our current sources of capital, we intend to focus capital expenditures for 2011 on completing the remaining five previously drilled wells, completing our exploratory test well that was in progress at year-end 2010, drilling a second test well to continue to evaluate resource potential below the Williams Fork formation in the Vega Area, and drilling a Vega Area lease preservation well. Although our available capital is limited we expect it will be sufficient to allow for the funding of these development plans. These plans may be adjusted from time to time depending on commodity prices, exploratory well test results, capital availability or other factors.

Liquidity and Capital Resources

Our sources of liquidity and capital resources historically have been net cash provided through the issuance of debt and equity securities when market conditions permit, operating activities, sales of oil and gas properties, and through borrowings under our credit facility. The primary uses of our liquidity and capital resources have been in the development and exploration of oil and gas properties. In the past, these sources of liquidity and capital have been sufficient to meet our needs. In 2010, to address our liquidity needs, we sold certain non-core assets to Wapiti Oil & Gas, LLC for $130.0 million.

We believe that the amounts available under our credit facility as recently amended, combined with our net cash from operating activities, will provide us with sufficient funds to fund our operating expenses planned and capital development activities described herein and maintain current debt service obligations. As discussed above, our 2011 capital expenditure program, and in particular our drilling and completion capital budget for the Vega Area, is dependent on the results of our completion activities on the Vega Area exploratory test wells that are currently underway. To the extent cash flow from operating activities are not sufficient to support our future capital expenditure program, and in order to address the January 2012 maturity of our credit facility and the potential mandatory redemption in May 2012 of our $115.0 million convertible notes, it is likely that we will need to seek sources of long-term capital (including the issuance of equity, debt instruments, sales of assets and joint venture financing), as well as consider other potential corporate transactions such as a sale of the company. The timing, term, size, and pricing of any such financing or transaction will depend on investor interest and market conditions, as well as the Company's drilling and completion results, and there can be no assurance that we will be able to obtain any such financing or consummate any such transaction, and if so, that it will be on terms satisfactory to the Company.

Our Credit Facility

On December 29, 2010, we amended and restated our credit agreement (the "MBL Credit Agreement") whereby the former lenders assigned their interests to Macquarie Bank Limited ("MBL"). The MBL Credit Agreement provides for a revolving loan and a term loan each with a maturity date of January 31, 2012. The revolving loan has an initial borrowing base of $30.0 million and the term loan had an initial commitment of $20.0 million subject to a development plan that must be approved by MBL. As of December 31, 2010, we had approximately $6.2 million of availability under the term loan based on the MBL approved development plan. See Note 7, "Long-Term Debt" to the accompanying consolidated financial statements. At December 31, 2010, we were in compliance with the financial covenants under the MBL Credit Agreement.

On March 14, 2011, we entered into an amendment to the MBL Credit Agreement that increased the availability under the term loan at the time from $6.2 million to $25.0 million, and doesn't require repayments of the term loan until the January 2012 maturity date. Specifically, among other changes, the amendment provided for an increase in the term loan commitment from $20.0 million to $25.0 million and removed the requirement that advances under the term loan be subject to approval of a development plan. In addition, so long as Delta is not in default under the MBL Credit Agreement, Delta is not required to comply with certain cash management provisions, including the previous requirement to repay any term loan advances outstanding on a monthly basis with 100% of net operating cash flows. See Note 20, "Subsequent Events" to the accompanying consolidated financial statements.

DHS Credit Facility

At December 31, 2010, DHS was out of compliance with the debt covenants under its credit facility and subsequently entered into a Forbearance Agreement with LCPI which expires on March 25, 2011. The DHS credit facility matures on August 31, 2011 and, as such, all amounts outstanding under the DHS credit facility are classified as a current liability in the accompanying consolidated balance sheet as of December 31, 2010. Accordingly, DHS is facing significant requirements to fund obligations in excess of its existing sources of liquidity when the forbearance agreement expires. DHS is in discussions with its credit facility lender regarding further amendments, waivers or other restructuring of the credit facility, but there can be no assurance that the lender will agree to any such amendments. In addition, subsequent to year-end, the Board of Directors of DHS engaged transaction advisors to commence a strategic alternatives process, focused on a sale of the company or substantially all of its assets. There can be no assurance that the terms offered by a potential buyer, if any, will be acceptable to the DHS shareholders. Additionally, the consummation of certain transactions are subject to the approval of DHS's senior lender and the proceeds received will be required to be used to pay down amounts outstanding under its DHS credit facility.

Capital Resources and Requirements

Our accompanying financial statements have been prepared assuming we will continue as a going concern. During the year ended December 31, 2010, significant improvements to our liquidity position were achieved through the Wapiti Transaction described above and the amendment of our credit facility. However, the MBL Credit Agreement matures in January 2012 and the holders of our $115.0 million convertible notes can require us to repurchase the notes at par on May 1, 2012. Thus, our ability to continue as a going concern could be dependent upon our lender's willingness to amend the terms or extend the maturity of our credit facility, the convertible note holders' willingness to amend or restructure the convertible notes, or our success in generating additional sources of capital in the near future.

As of December 31, 2010, our corporate rating and senior unsecured debt rating were Caa3 and Ca, respectively, as issued by Moody's Investors Service. Moody's outlook was "negative." As of December 31, 2010, our corporate credit and senior unsecured debt ratings were CCC and CCC-, respectively, as issued by Standard and Poor's ("S&P"). S&P's outlook on its rating was "negative."

Our future cash requirements are also largely dependent upon the number and timing of projects included in our capital development plan, most of which are discretionary. The prices we receive for future oil and natural gas production and the level of production have a significant impact on our operating cash flows. Beyond the volumes for which we have entered into derivative contracts, we are unable to predict with any degree of certainty the prices we will receive for our future oil and gas production or the success of our exploration and development activities in generating additional production.

Cash Flows

On July 30, 2010, we completed the $130.0 million sale of certain non-core properties to Wapiti. Proceeds were used to reduce credit facility borrowings and fund development. During 2010, we divested of our equity interests in certain unconsolidated affiliates for proceeds of $6.7 million. With proceeds from these transactions, we have reduced our borrowings outstanding under our credit facility from $124.0 million at December 31, 2009 to $29.1 million at December 31, 2010. In addition, we reduced our accounts payable and offshore litigation payable from $58.1 million at December 31, 2009 to $36.2 million at December 31, 2010.

As shown in the accompanying financial statements and discussed elsewhere herein, we experienced a net loss attributable to Delta common stockholders of $182.3 million for the year ended December 31, 2010. We were in compliance with our financial covenants under our credit facility at December 31, 2010.

During the year ended December 31, 2010, we had an operating loss of $102.5 million, net cash used in operating activities of $31.5 million and net cash used in financing activities of $212.6 million. During this period we spent $41.6 million on oil and gas development activities. At December 31, 2010, we had $15.7 million in cash and $7.1 million available under our credit facility, total assets of $1.0 billion and a debt to capitalization ratio of 41.1%. Debt, excluding installments payable on property acquisition which are secured by restricted cash deposits, at December 31, 2010 totaled $357.0 million, comprised of $98.7 million of bank debt ($29.1 million of our indebtedness under our MBL Credit Agreement and $69.6 million of DHS indebtedness, of which the DHS indebtedness was classified as current at December 31, 2010), $149.6 million of senior subordinated notes and $104.0 million of senior convertible notes. In accordance with applicable accounting rules, the senior convertible notes are recorded at a discount to their stated amount due of $115.0 million.

Results of Operations

The following discussion and analysis relates to items that have affected our results of operations for the years ended December 31, 2010, 2009 and 2008. The following table sets forth (in thousands), for the periods presented, selected historical statements of operations data. The information contained in the table below should be read in conjunction with our consolidated financial statements and accompanying notes included in this Annual Report on Form 10-K.

	Years Ended December 31,		
	2010	2009	2008
Revenue:			
Oil and gas sales	$ 94,388	$ 82,723	$ 192,815
Contract drilling and trucking fees	53,212	13,680	49,445
Gain on offshore litigation settlement, net of loss on property sales	(795)	73,800	-
Total revenue	146,805	170,203	242,260
Operating Expenses:			
Lease operating expense	24,566	26,439	27,896
Transportation expense	15,211	10,057	7,925
Production taxes	3,727	3,032	11,185
Exploration expense	1,337	2,604	10,975
Dry hole costs and impairments	43,572	176,871	411,103
Depreciation, depletion, amortization and accretion – oil and gas	58,265	81,335	80,218
Drilling and trucking operating expenses	42,248	15,293	32,594
Goodwill and drilling equipment impairments	-	6,508	29,349
Depreciation and amortization – drilling and trucking	19,964	22,917	14,134
General and administrative expense	41,130	41,414	53,607
Executive severance expense, net	(674)	3,739	-
Total operating expenses	249,346	390,209	678,986
Operating loss	(102,541)	(220,006)	(436,726)
Other income and (expense):			
Interest expense and financing costs, net	(37,247)	(52,581)	(35,357)
Other income (expense)	(1,409)	1,049	(5,210)
Realized gain (loss) on derivative instruments, net	(5,835)	(1,115)	18,383
Unrealized gain (loss) on derivative instruments, net	23,979	(26,972)	3,365
Income (loss) from unconsolidated affiliates	1,738	(15,473)	3,375
Total other expense	(18,774)	(95,092)	(15,444)
Loss from continuing operations before income taxes and discontinued operations	(121,315)	(315,098)	(452,170)
Income tax expense (benefit)	543	215	(11,723)
Loss from continuing operations	(121,858)	(315,313)	(440,447)
Loss from results of operations and sale of discontinued operations, net of tax	(72,156)	(34,371)	(27,103)
Net loss	(194,014)	(349,684)	(467,550)
Less net loss attributable to non-controlling interest	11,682	20,901	11,486
Net loss attributable to Delta common stockholders	$ (182,332)	$ (328,783)	$ (456,064)

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Net Income (Loss) Attributable to Delta Common Stockholders. Net loss attributable to Delta common stockholders was $182.3 million, or $0.66 per diluted common share, for the year ended December 31, 2010, compared to net loss of $328.8 million or $1.56 per diluted common share, for the year ended December 31, 2009. Loss from continuing operations decreased from $315.3 million for the year ended December 31, 2009 to a loss of $121.9 million for the year ended December 31, 2010. The decreased loss was primarily due to fewer dry holes and impairments recorded in 2010 as compared to 2009, improved oil and gas operations, changes in unrealized gains (losses) on derivative instruments, and lower interest and financing costs. Explanations of significant items affecting comparability between periods are discussed by the financial statement captions below.

Oil and Gas Sales. During the year ended December 31, 2010, oil and gas sales from continuing operations were $94.4 million, as compared to $82.7 million for the comparable period a year earlier. During the year ended December 31, 2010, production from continuing operations decreased by 21% and the average natural gas and oil price increased 62% and 35%, respectively. The average gas price received during the year ended December 31, 2010 was $5.01 per Mcf compared to $3.09 per Mcf for the year earlier period and the average oil price received during the year ended December 31, 2010 was $70.90 per Bbl compared to $52.45 per Bbl for the year earlier period. The production decrease was primarily related to divestitures in the Gulf Coast area in 2010 and production declines in the Rocky Mountain Region where completion activity did not resume until late 2010.

Contract Drilling and Trucking Fees. Drilling and trucking revenues for the year ended December 31, 2010 increased to $53.2 million compared to $13.7 million for the prior year period. Drilling and trucking revenues increased significantly in 2010 due to higher third party rig utilization in 2010 compared to the prior year, resulting from increased drilling activity attributable in particular to higher oil prices. Drilling and trucking revenues earned on wells drilled for Delta have been eliminated in consolidation.

Gain on Offshore Litigation Settlement, Net of Loss on Property Sales. During 2009, we recorded gains of $79.5 million related to two offshore litigation awards. See Note 4, "Oil and Gas Properties," to the accompanying financial statements. In addition, during the fourth quarter of 2009, we recorded losses of $5.7 million on several non-core property divestiture transactions. During 2010, minor losses of $795,000 were recorded on several non-core property divestitures.

Production and Cost Information

Production volumes, average prices received and cost per equivalent Mcf for the years ended December 31, 2010 and 2009 are as follows:

	Years Ended December 31,	
	2010	2009
Production – Continuing Operations:		
Oil (MBbl)	500	734
Gas (MMcf)	11,759	14,319
Total (MMcfe)	14,759	18,727
Average Price – Continuing Operations:		
Oil (per barrel)	$ 70.90	$ 52.45
Gas (per Mcf)	$ 5.01	$ 3.09
Costs per Mcfe – Continuing Operations:		
Lease operating expense	$ 1.66	$ 1.41
Production taxes	$ 0.25	$ 0.16
Transportation costs	$ 1.03	$ 0.54
Depletion expense	$ 3.73	$ 4.19

Lease Operating Expense. Lease operating expenses for the year ended December 31, 2010 were $24.6 million compared to $26.4 million for the year earlier period. Lease operating expense from continuing operations for the year ended December 31, 2010 decreased $1.8 million from the year earlier period. However, lease operating expenses increased on a per unit basis primarily due to the effect of fixed costs spread over a 21% decline in production volumes. The average lease operating expense was $1.66 per Mcfe in 2010 as compared to $1.41 per Mcfe for the year earlier period.

Transportation Expense. Transportation expense for the year ended December 31, 2010 was $15.2 million, comparable to prior year costs of $10.1 million, up 91% on a per unit basis from $0.54 per Mcfe to $1.03 per Mcfe. The increase on a per unit basis is primarily the result of changes to our Vega gas marketing contract that went into effect in October 2009 whereby our gas is processed through a higher efficiency plant. Although the Vega area transportation costs increased on a per unit basis in 2010 as a result of these operations, this was more than offset by higher revenues in the Vega area from improved natural gas liquids recoveries and a greater percentage of liquids proceeds retained.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the year ended December 31, 2010 were $1.3 million compared to $2.6 million for the year earlier period. Exploration activities in 2010 were limited due to our funding constraints and primarily consisted of delay rental payments. In contrast, significant amounts were spent in 2009 on seismic shoots in several areas of exploration activity and delay rental payments were nearly double the 2010 level.

Dry Hole Costs and Impairments. We incurred dry hole costs of approximately $86,000 for the year ended December 31, 2010 compared to $33.6 million for the comparable period a year ago. As of December 31, 2010, we had one exploratory well in progress, the results of which could, if unsuccessful, impact dry hole costs in future periods. For the year ended December 31, 2009, our dry hole costs related primarily to our Columbia River Basin exploratory well (the Gray Well) in Washington.

During the year ended December 31, 2010, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties and other items totaling approximately $43.5 million primarily related to proved impairments to our Opossum Hollow and Golden Prairie fields of $1.1 million and unproved impairments of $30.0 million related to our Columbia River Basin leasehold, Hingeline leasehold, Haynesville leasehold, Delores River leasehold, Howard Ranch leasehold, and our non-operated Garden Gulch field in the Piceance Basin. Other impairments primarily included $6.7 million for the produced water handling facility in Vega and $4.9 million to reduce the Paradox pipeline carrying value to its estimated fair value. These impairments generally resulted from the lack of success in marketing these non-core assets combined with our lack of plans to develop the acreage.

During the year ended December 31, 2009, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $143.3 million primarily related to our non-operated Garden Gulch field in the Piceance Basin of $38.6 million, Haynesville Shale of $27.5 million, Columbia River Basin of $21.4 million, Lighthouse Bayou of $14.8 million, various Gulf Coast fields of $18.5 million, Vega surface land of $10.5 million, various Rockies fields of $5.4 million, pipe and tubular inventory of $4.3 million and Paradox pipeline of $1.9 million. These impairments generally resulted from sustained lower commodity prices for most of 2009, near term expiring leasehold, unsuccessful drilling results, or our inability to meet contractual drilling obligations.

Depreciation, Depletion and Amortization – Oil and Gas. Depreciation, depletion and amortization expense decreased 28% to $58.3 million for the year ended December 31, 2010, as compared to $81.3 million for the year earlier period. Depletion expense for the year ended December 31, 2010 was $55.0 million compared to $78.4 million for the year ended December 31, 2009. The 30% decrease in depletion expense was primarily due to a 21% decrease in production from continuing operations and an 11% decrease in the depletion rate. Our depletion rate decreased to $3.73 per Mcfe for the year ended December 31, 2010 from $4.19 per Mcfe for the year earlier period. The decrease is primarily due to a change in the mix of our properties as a result of the Wapiti Transaction and additional Rockies reserves recorded in 2010 as a result of completion activities and use of improved fracturing methods.

Drilling and Trucking Operating Expenses. We had drilling and trucking operating expenses of $42.2 million during the year ended December 31, 2010 compared to $15.3 million during the year ended December 31, 2009. The increase is due to higher third party rig utilization during 2010.

Depreciation and Amortization – Drilling and Trucking. Depreciation and amortization expense – drilling and trucking decreased to $20.0 million for the year ended December 31, 2010 as compared to $22.9 million for the prior year period. The decrease is due to the full year effect of impairments taken in 2009 and sales of rig equipment. Depreciation expense is recorded on a straight line basis and is not impacted by changes in the utilization rate.

General and Administrative Expense. General and administrative expense decreased slightly to $41.1 million for the year ended December 31, 2010, as compared to $41.4 million for the comparable prior year period. The decrease in general and administrative expenses is primarily attributed to lower expenses incurred on employee benefits and wages from reductions in force during 2010 and 2009 but was offset by significant costs associated with the strategic alternatives process and bad debt expense recorded by DHS. We expect further reductions to full year cash general and administrative expenses in 2011 as cost saving measures implemented in 2010 take full effect in 2011.

Executive Severance Expense, Net. On May 26, 2009, our then Chairman of the Board of Directors and Chief Executive Officer, Roger A. Parker, resigned from Delta. In consideration for Mr. Parker's resignation and his agreement to (a) relinquish all his rights under his employment agreement, his change-in-control agreement, certain stock agreements, bonuses relating to past and pending transactions benefiting Delta, and any other interests he might claim arising from his efforts as Chairman of our Board of Directors and/or Chief Executive Officer, and (b) stay on as a consultant to facilitate an orderly transition and to assist in certain pending transactions, Delta agreed to pay Mr. Parker $4.7 million in cash, issue to him 1.0 million shares of Delta common stock, pay him the aggregate of any accrued unpaid salary, vacation days and reimbursement of his reasonable business expenses incurred through the effective date of the agreement, and provide to him insurance benefits similar to his pre-resignation benefits for a thirty-six month period. The Severance Agreement also contained mutual releases and non-disparagement provisions, as well as other customary terms. In addition, $2.8 million of equity compensation costs previously recorded in the consolidated financial statements related to shares which were forfeited as a result of the severance agreement were reversed and reflected as a reduction of executive severance expense.

On July 6, 2010, John Wallace, our then President, Chief Operating Officer and a Director, resigned from all of his positions as director, officer and employee of Delta and any of our subsidiaries. In conjunction with such resignation, we entered into a severance agreement with Mr. Wallace pursuant to which he agreed to (a) relinquish certain rights under his employment agreement, his change-in-control agreement, certain stock agreements, bonuses relating to past and pending transactions benefiting Delta, and certain other interests he might claim arising from his efforts in his previous capacities with us and our subsidiaries, and (b) make himself reasonably available to answer questions to facilitate an orderly transition. Under the terms of his severance arrangement, we paid Mr. Wallace a lump sum of $1.6 million, paid him his salary for the full month in which his resignation occurred and for his accrued vacation days, reimbursed him for his reasonable business expenses incurred through the effective date of the agreement, and agreed to provide to him insurance benefits similar to his pre-resignation benefits for the period in which Mr. Wallace is entitled to receive COBRA coverage under applicable law. The severance agreement also contained mutual releases and non-disparagement provisions, as well as other customary terms. In addition, $2.3 million of equity compensation costs previously recorded in the consolidated financial statements related to performance shares forfeited prior to their derived service period being completed as a result of the severance agreement were reversed and reflected as a reduction of executive severance expense.

Interest Expense and Financing Costs, Net. Interest expense and financing costs decreased 29% to $37.2 million for the year ended December 31, 2010, as compared to $52.6 million for the comparable year earlier period. The decrease is primarily related to lower average outstanding Delta and DHS credit facility balances during 2010 as compared to 2009. The decrease is also related to a greater write-off of unamortized deferred financing costs and waiver fees related to the amendments to our credit facilities in 2009 compared to 2010. In addition, the year ended December 31, 2009 included $1.0 million of interest expense related to the repurchase from Tracinda of offshore litigation contingent payment rights and $643,000 for the write off of previously unamortized deferred financing costs related to the DHS credit agreement.

Realized Gain on Derivative Instruments, Net. During the year ended December 31, 2010, we recognized $5.8 million of realized losses associated with settlements on derivative contracts and $1.1 million of realized losses on derivative instruments for the year ended December 31, 2009.

Unrealized Gain on Derivative Instruments, Net. We recognize mark-to-market gains or losses in current earnings instead of deferring those amounts in accumulated other comprehensive income. Accordingly, we recognized $24.0 million of unrealized gain on derivative instruments in other income and expense during the year ended December 31, 2010 compared to an unrealized loss of $27.0 million for the comparable prior year period, primarily due to changes in the movement of commodity prices in the respective years.

Income (Loss) From Unconsolidated Affiliates. Income from unconsolidated affiliates during the year ended December 31, 2010 is primarily the result of our pro-rata share of net income of our unconsolidated affiliates. During 2010, we sold our investment in Ally Equipment for a loss of $522,000 and we sold our investment in Delta Oilfield Tank Company ("DOTC") for a gain of $676,000.

Loss from unconsolidated affiliates during the year ended December 31, 2009 was primarily the result of $3.4 million of impairments to the carrying value of our investment in Ally Equipment, $3.3 million in Delta Oilfield Tank Company ("DOTC"), $1.4 million in Collbran Valley Gas Gathering, LLC ("CVGG") and $1.0 million in Arista in addition to the bad debt reserve of $5.0 million to reduce the carrying value of our note receivable from DOTC to the amount estimated to be collectible. These impairments were generally the result of the industry wide downturn caused by the significant decline in commodity prices and the limitation on availability of credit in 2008 and through late 2009 which had a material adverse impact on our investments.

Income Tax Benefit (Expense). Due to our continuing losses, we were required by the "more likely than not" threshold for assessing the realizability of deferred tax assets, to record a valuation allowance for our deferred tax assets beginning in 2007. Our subsidiary, DHS, was similarly required to record a valuation allowance for its deferred tax assets beginning in 2009. Our income tax expense for the years ended December 31, 2010 and 2009 primarily relates to the amortization of other tax assets generated for Delta by work performed for Delta by DHS. No benefit was provided in either period for Delta or DHS net operating losses.

Discontinued Operations. The results of operations and impairment loss related to non-core property interests sold in the Garden Gulch field, Baffin Bay field, and Bull Canyon field as well as our interest in our wholly-owned subsidiary Piper Petroleum have been reflected as discontinued operations as a result of the sale to Wapiti. In separate transactions, we sold our interests in the Howard Ranch and Laurel Ridge fields which are also included in discontinued operations.

The following table shows the total revenues and expenses included in discontinued operations for the above mentioned oil and gas properties for the years ended December 31, 2010 and 2009 (dollar amounts in thousands):

	Years Ended December 31,	
	2010	2009
Production – Discontinued Operations:		
Oil (Mbbl)	15	27
Gas (Mmcf)	1,911	3,272
Total Production (Mmcfe) – Discontinued Operations	2,001	3,434
Revenues	$ 9,724	$ 12,239
Operating expenses:		
Lease operating expense	2,781	4,864
Transportation expense	1,461	1,555
Production taxes	612	820
Depreciation, depletion, amortization and accretion	13,842	27,170
Impairments	92,162	12,201
Total operating expenses	110,858	46,610
Loss from discontinued operations	(101,134)	(34,371)
Income tax expense	-	-
Loss from results of operations of discontinued properties, net of tax	(101,134)	(34,371)
Gain on sales of discontinued operations, net	28,978	-
Total loss from discontinued operations	$ (72,156)	$ (34,371)

On July 23, 2010, we entered into a definitive Purchase and Sale Agreement with Wapiti to sell all or a portion of our interest in various non-core assets primarily located in Colorado, Texas, and Wyoming for gross cash proceeds of $130.0 million resulting in a net loss of $66.5 million (including impairment losses of $96.2 million). For financial reporting purposes, a $4.0 million impairment loss is included within dry hole costs and impairments in continuing operations, $92.2 million of impairments are included within loss from discontinued operations, and a $29.7 million gain on sale is included in gain on sale of discontinued operations.

During 2010, we also sold our Howard Ranch properties for $550,000, recognizing a loss on the sale of $687,000. During 2009, we recorded impairments on the Howard Ranch and Laurel Ridge fields of $1.5 million and $10.7 million, respectively, as a result of the significant decline in commodity pricing for most of 2009 causing downward revisions to proved reserves which led to impairments.

Net Loss Attributable to Non-Controlling Interest. Non-controlling interest represents the minority investors' proportionate share of the income or loss of DHS in which they hold an interest. During the years ended December 31, 2010 and 2009, DHS reported significant losses from low rig utilization rates which resulted in a non-controlling interest credit to earnings.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Net Income (Loss) Attributable to Delta Common Stockholders. Net loss attributable to Delta common stockholders was $328.8 million, or $1.56 per diluted common share, for the year ended December 31, 2009, compared to net loss of $456.1 million or $4.77 per diluted common share, for the year ended December 31, 2008. Loss from continuing operations decreased from $440.4 million for the year ended December 31, 2008 to a loss of $315.3 million for the year ended December 31, 2009. The decreased loss was primarily due to fewer dry holes and impairments recorded in 2009 as compared to 2008, offset by lower oil and gas sales. Explanations of significant items affecting comparability between periods are discussed by the financial statement captions below.

Oil and Gas Sales. During the year ended December 31, 2009, oil and gas sales from continuing operations were $82.7 million, as compared to $192.8 million for the comparable period a year earlier. During the year ended December 31, 2009, production from continuing operations decreased by 10% and the average natural gas and oil price decreased 55% and 43%, respectively. The average gas price received during the year ended December 31, 2009 was $3.09 per Mcf compared to $6.92 per Mcf for the year earlier period and the average oil price received during the year ended December 31, 2009 was $52.45 per Bbl compared to $92.47 per Bbl for the year earlier period. The production decrease was primarily related to production declines in the Rockies and Gulf Coast areas that were not offset by additional drilling or completion activities due to the limited capital budget in 2009.

Contract Drilling and Trucking Fees. Drilling and trucking revenues for the year ended December 31, 2009 decreased to $13.7 million compared to $49.4 million for the prior year period. Drilling and trucking revenues decreased in 2009 due to lower third party rig utilization in 2009 compared to the prior year, resulting from a significant industry slowdown attributable to lower commodity prices. Drilling and trucking revenues earned on wells drilled for Delta have been eliminated in consolidation.

Gain on Offshore Litigation Settlement Net of Loss on Property Sales. During 2009, we recorded gains of $79.5 million related to two offshore litigation awards. See Note 4, "Oil and Gas Properties," to the accompanying financial statements. In addition, during the fourth quarter of 2009, we recorded losses of $5.7 million on several non-core property divestiture transactions.

Production and Cost Information

Production volumes, average prices received and cost per equivalent Mcf for the years ended December 31, 2009 and 2008 are as follows:

	Years Ended December 31,	
	2009	2008
Production – Continuing Operations:		
Oil (MBbl)	734	950
Gas (MMcf)	14,319	15,164
Total (MMcfe)	18,727	20,863
Average Price – Continuing Operations:		
Oil (per barrel)	$ 52.45	$ 92.47
Gas (per Mcf)	$ 3.09	$ 6.92
Costs per Mcfe – Continuing Operations:		
Lease operating expense	$ 1.41	$ 1.34
Production taxes	$ 0.16	$ 0.54
Transportation costs	$ 0.54	$ 0.38
Depletion expense	$ 4.19	$ 3.72

Lease Operating Expense. Lease operating expenses for the year ended December 31, 2009 were $26.4 million compared to $27.9 million for the year earlier period. Lease operating expense from continuing operations for the year ended December 31, 2009 remained relatively flat from the year earlier period. However, lease operating expenses increased on a per unit basis primarily due to the effect of fixed costs spread over declining production volumes. The average lease operating expense was $1.41 per Mcfe in 2009 as compared to $1.34 per Mcfe for the year earlier period.

Transportation Expense. Transportation expense for the year ended December 31, 2009 was $10.1 million, comparable to prior year costs of $7.9 million, but up 42% from $0.38 per Mcfe to $0.54 per Mcfe. The increase on a per unit basis is primarily the result of changes to our Vega gas marketing contract that went into effect in October 2009 whereby our gas is processed through a higher efficiency plant. This increase in cost was more than offset by higher revenues in the Vega area from improved natural gas liquids recoveries and a greater percentage of liquids proceeds retained.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the year ended December 31, 2009 were $2.6 million compared to $11.0 million for the year earlier period. Exploration activities in 2009 were limited due to our funding constraints and primarily consisted of delay rental payments and limited seismic activity. In contrast, significant amounts were spent in 2008 on seismic shoots in several areas of exploration activity.

Dry Hole Costs and Impairments. We incurred dry hole costs of approximately $33.6 million for the year ended December 31, 2009 compared to $111.9 million for the comparable 2008 period. For the year ended December 31, 2009, our dry hole costs related primarily to our Columbia River Basin exploratory well (the Gray Well) in Washington. For the year ended December 31, 2008, our dry hole costs related primarily to Greentown and Hingeline exploratory projects in Utah.

During the year ended December 31, 2009, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $143.3 million primarily related to our non-operated Garden Gulch field in the Piceance Basin of $38.6 million, Haynesville Shale of $27.5 million, Columbia River Basin of $21.4 million, Lighthouse Bayou of $14.8 million, various Gulf Coast fields of $18.5 million, Vega surface land of $10.5 million, various Rockies fields of $5.4 million, pipe and tubular inventory of $4.3 million and Paradox pipeline of $1.9 million. These impairments generally resulted from sustained lower commodity prices for most of 2009, near term expiring leasehold, unsuccessful drilling results, or our inability to meet contractual drilling obligations.

During the year ended December 31, 2008, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $277.7 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas of $192.5 million, Paradox field in Utah of $30.5 million, Howard Ranch and Bull Canyon fields in the Rockies of $4.1 million, Utah Hingeline of $40.8 million and our offshore California field of $9.8 million. In addition, we recorded impairments to our Paradox pipeline of $21.5 million. The impairments resulted primarily from the significant decline in commodity pricing during the fourth quarter of 2008 and unsuccessful drilling results.

Depreciation, Depletion and Amortization – Oil and Gas. Depreciation, depletion and amortization expense increased 1% to $81.3 million for the year ended December 31, 2009, as compared to $80.2 million for the year earlier period. Depletion expense for the year ended December 31, 2009 was $78.4 million compared to $77.7 million for the year ended December 31, 2008. The 1% increase in depletion expense was primarily due to a 13% increase in the depletion rate. Our depletion rate increased to $4.19 per Mcfe for the year ended December 31, 2009 from $3.72 per Mcfe for the year earlier period. The increase is primarily due to the effects of low Rockies gas prices throughout most of 2009 and low 12-month average historical prices at December 31, 2009 on the reserves used in our depletion calculation.

Drilling and Trucking Operating Expenses. We had drilling and trucking operating expenses of $15.3 million during the year ended December 31, 2009 compared to $32.6 million during the year ended December 31, 2008. The decrease is due to lower third party rig utilization during 2009 but is not proportional to the decline in contract drilling and trucking fees due to fixed costs and costs associated with a large number of stacked rigs.

Goodwill and Drilling Equipment Impairments. We performed our annual DHS goodwill impairment test during the quarter ended September 30, 2008; however, due to the deterioration in the market conditions and decreased utilization, we re-evaluated the DHS goodwill and the fair values of our rigs as of December 31, 2008. We determined that the book value of the rigs was impaired by $21.6 million. As a result of the analysis performed at year-end 2008, we also wrote off the entire amount of DHS's goodwill of $7.7 million. During the second quarter of 2009, we concluded that DHS spare equipment required impairments of approximately $6.5 million.

Depreciation and Amortization – Drilling and Trucking. Depreciation and amortization expense – drilling and trucking increased to $22.9 million for the year ended December 31, 2009 as compared to $14.1 million for the prior year period. The increase is due to less drilling done by DHS for us in 2009 as compared to 2008. Depreciation expense is recorded on a straight line basis and is not impacted by changes in the utilization rate.

General and Administrative Expense. General and administrative expense decreased 23% to $41.4 million for the year ended December 31, 2009, as compared to $53.6 million for the comparable prior year period. The decrease in general and administrative expenses is primarily attributed to lower expenses incurred on employee benefits and wages from reductions in force during 2009 and a decrease in non-cash stock compensation expense.

Executive Severance Expense, Net. On May 26, 2009, our then Chairman of the Board of Directors and Chief Executive Officer, Roger A. Parker, resigned from Delta. In consideration for Mr. Parker's resignation and his agreement to (a) relinquish all his rights under his employment agreement, his change-in-control agreement, certain stock agreements, bonuses relating to past and pending transactions benefiting Delta, and any other interests he might claim arising from his efforts as Chairman of our Board of Directors and/or Chief Executive Officer, and (b) stay on as a consultant to facilitate an orderly transition and to assist in certain pending transactions, Delta agreed to pay Mr. Parker $4.7 million in cash, issue to him 1.0 million shares of Delta common stock, pay him the aggregate of any accrued unpaid salary, vacation days and reimbursement of his reasonable business expenses incurred through the effective date of the agreement, and provide to him insurance benefits similar to his pre-resignation benefits for a thirty-six month period. The Severance Agreement also contained mutual releases and non-disparagement provisions, as well as other customary terms. In addition, $2.8 million of equity compensation costs previously recorded in the consolidated financial statements related to shares which were forfeited as a result of the severance agreement were reversed and reflected as a reduction of executive severance expense.

Interest Expense and Financing Costs, Net. Interest expense and financing costs, net increased 49% to $52.6 million for the year ended December 31, 2009, as compared to $35.4 million for the comparable year earlier period. The increase is primarily related to the write-off of deferred financing costs in conjunction with our reduced borrowing base, offshore litigation contingent payment financing costs, higher average debt balances and interest rates on the Delta and DHS credit facilities, non-cash accretion of discount on an installment obligation payable to EnCana Oil and Gas (USA) Inc. ("EnCana"), and a decrease in interest income to $2.5 million in 2009 from $10.1 million in 2008.

Other Income and (Expense). Other expense for the year ended December 31, 2008 includes $4.6 million of impairment charges related to our auction rate securities and $1.3 million related to a forfeited deposit for a rig acquisition that DHS was unable to close due to Lehman's failure to fund under the DHS credit facility. Other income in 2009 was insignificant.

Realized Gain (Loss) on Derivative Instruments, Net. During the years ended December 31, 2009 and 2008, we recognized $1.1 million of realized losses and $18.4 million of realized gains, respectively, associated with settlements on derivative contracts.

Unrealized Gain (Loss) on Derivative Instruments, Net. We recognize mark-to-market gains or losses in current earnings instead of deferring those amounts in accumulated other comprehensive income. Accordingly, we recognized $27.0 million of unrealized losses on derivative instruments in other income and expense during the year ended December 31, 2009 compared to an unrealized gain of $3.4 million for the comparable prior year period, primarily due to changes in the movement of commodity prices in the respective years.

Income (Loss) From Unconsolidated Affiliates. Loss from unconsolidated affiliates during the year ended December 31, 2009 was primarily the result of $3.4 million of impairments to the carrying value of our investment in Ally Equipment, $3.3 million in Delta Oilfield Tank Company ("DOTC"), $1.4 million in Collbran Valley Gas Gathering, LLC ("CVGG") and $1.0 million in Arista in addition to the bad debt reserve of $5.0 million to reduce the carrying value of our note receivable from DOTC to the amount estimated to be collectible. These impairments were generally the result of the industry wide downturn caused by the significant decline in commodity prices and the limitation on availability of credit in 2008 and through late 2009 which had a material adverse impact on our investments.

Income from unconsolidated affiliates during 2008 is comprised of our pro-rata share of net income from our unconsolidated affiliates.

Income Tax Benefit (Expense). Due to our continuing losses, we were required by the "more likely than not" threshold for assessing the realizability of deferred tax assets, to record a valuation allowance for our deferred tax assets beginning in 2007. Our subsidiary, DHS, was similarly required to record a valuation allowance for its deferred tax assets beginning in 2009. Income tax expense for the year ended December 31, 2009 primarily relates to the amortization of other tax assets generated for Delta by work performed for Delta by DHS. No benefit was provided in 2009 for Delta or DHS net operating losses. Income tax benefit for the year ended December 31, 2008 primarily related to the deferred tax benefit recorded on DHS net operating losses.

Discontinued Operations. The results of operations and impairment loss related to non-core property interests sold in the Garden Gulch field, Baffin Bay field, and Bull Canyon field, as well as our interest in our wholly-owned subsidiary Piper Petroleum, have been reflected as discontinued operations as a result of the sale to Wapiti in 2010. In separate transactions in 2010, we also sold our interest in the Howard Ranch and Laurel Ridge fields which are also included in discontinued operations.

The following table shows the total revenues and expenses included in discontinued operations for the above mentioned oil and gas properties for the years ended December 31, 2009 and 2008 (dollar amounts in thousands):

	Years Ended December 31,	
	2009	2008
Production – Discontinued Operations:		
Oil (Mbbl)	27	43
Gas (Mmcf)	3,272	3,784
Total Production (Mmcfe) – Discontinued Operations	3,434	4,042
Revenues	$ 12,239	$ 28,918
Operating expenses:		
Lease operating expense	4,864	5,612
Transportation expense	1,555	3,470
Production taxes	820	890
Depreciation, depletion, amortization and accretion	27,170	18,907
Impairments	12,201	27,860
Total operating expenses	46,610	56,739
Loss from discontinued operations	(34,371)	(27,821)
Income tax expense	-	-
Loss from results of operations of discontinued properties, net of tax	(34,371)	(27,821)
Gain on sale of discontinued operations	-	718
Total loss from discontinued operations	$ (34,371)	$ (27,103)

During 2009, we recorded impairments on the Howard Ranch and Laurel Ridge fields of $1.5 million and $10.7 million, respectively, as a result of the significant decline in commodity pricing for most of 2009 causing downward revision to proved reserves. During 2008, we recorded impairments on the Howard Ranch and Bull Canyon fields of $21.8 million and $6.1 million, respectively, as a result of the significant decline in commodity pricing during the fourth quarter of 2008 and unsuccessful drilling results.

During the year ended December 31, 2008, we completed an asset exchange agreement where we acquired additional interests in our Midway Loop properties in exchange for cash and certain non-core properties. The transaction resulted in a gain on the disposition of the non-core properties of $718,000.

Net (Income) Loss Attributable to Non-Controlling Interest. Net (income) loss attributable to non-controlling interest represents the non-controlling investors' percentage of their share of income or losses from DHS in which they hold an interest. During the years ended December 31, 2009 and 2008, DHS generated a loss resulting in a non-controlling interest credit to earnings.

Historical Cash Flow

Our net cash used in operating activities was $31.5 million for the year ended December 31, 2010 compared to net cash provided by operating activities of $81.1 million for the year ended December 31, 2009. The decrease is primarily a result of offshore litigation proceeds received in 2009 and an increase in cash used for working capital purposes during 2010. Our net cash provided by investing activities increased to $197.8 million for the year ended December 31, 2010 compared to net cash used in investing activities of $47.4 million for the year earlier period, primarily due to proceeds from the Wapiti Transaction and our decreased drilling activity. Cash used in financing activities was $212.6 million for the year ended December 31, 2010 compared to net cash used in financing activities of $37.3 million for the comparable prior year period. Cash used in financing activities in 2010 was primarily comprised of a net $108.6 million of repayment of borrowings and $100.0 million of installments paid on property acquisition, primarily with funds from the Wapiti Transaction. Cash used in financing activities was lower in 2009 primarily due to net proceeds of $246.9 million received from the stock offering completed in May 2009.

Our cash flow from operating activities decreased from $140.7 million for the year ended December 31, 2008 to $81.1 million for the year ended December 31, 2009, primarily as a result of decreased production and lower commodity prices for most of the year. Our net cash used in investing activities decreased to $47.4 million for the year ended December 31, 2009 compared to net cash used in investing activities of $982.6 million for the year earlier period, primarily due to our decreased drilling and acquisition activity. Cash used in financing activities was $37.3 million for the year ended December 31, 2009 compared to $897.6 million for the comparable prior year period. Cash used in financing activities in 2009 was primarily comprised of $246.9 million of proceeds from the stock offering, offset by $181.0 million of repayment of borrowings and $100.0 million of installments paid on property acquisition and was higher in 2008 primarily due to cash received from the Tracinda transaction and additional bank borrowings.

Capital and Exploration Expenditures and Financing

Our capital and exploration expenditures and sources of financing for the years ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31,		
	2010	2009	2008
CAPITAL AND EXPLORATION EXPENDITURES:		(In thousands)	
Acquisitions:			
Piceance	$ -	$ -	$ 128,848
Haynesville	-	-	31,550
Columbia River Basin	-	-	25,000
Lighthouse Bayou	-	-	14,512
Austin Chalk incremental interests	-	-	13,855
Other	909	2,083	8,050
Other development costs	40,730	163,772	457,947
Drilling and trucking companies	2,549	1,785	52,970
Exploration costs	1,337	2,604	10,975
	$ 45,525	$ 170,244	$ 743,707
FINANCING SOURCES:			
Cash provided by (used in) operating activities	$ (31,538)	$ 81,144	$ 140,676
Stock issued for cash upon exercised options	-	-	4,827
Stock issued for cash, net	-	246,905	662,043
Net long-term borrowings (repayments)	(111,818)	(183,859)	232,120
Installments paid on property acquisition	(100,000)	(100,000)	-
Proceeds from sale of oil and gas properties	132,945	8,393	42,000
Proceeds from sale of drilling assets	665	9,111	3,201
Proceeds from sale of marketable securities	300	2,030	-
Investments in and notes issued to affiliates	-	295	(6,965)
Proceeds from sales of unconsolidated affiliates	6,654	-	-
Increase in restricted deposit	100,000	100,000	(300,000)
Minority interest contributions	-	-	12,000
Other	715	64	(1,488)
	$ (2,077)	$ 164,083	$ 788,414

We are unable to accurately predict our anticipated capital expenditures for fiscal year 2011, primarily due to the uncertainty relating to capital availability. We expect to announce our 2011 drilling plans once our well results have been evaluated.

Changes in Proved Reserve Quantities

Significant changes to our proved reserves are described below. See also Note 19, "Information Regarding Proved Oil and Gas Reserves (Unaudited)" in our accompanying consolidated financial statements.

During the year ended December 31, 2008, positive revisions totaling 166.4 Bcfe were primarily related to 10-acre downspacing of our Piceance Basin proved undeveloped reserves and the increase in proved reserves from extensions and discoveries of 162.7 Bcfe was comprised of Rocky Mountain proved reserve increases primarily from our Piceance Basin drilling program and related offset wells. Also, during 2008, we purchased incremental interests in our existing Piceance Basin acreage and acquired new interests in adjacent leasehold to expand our Vega Area totaling approximately 204.6 Bcfe. See Note 4, "Oil and Gas Properties – Year Ended December 31, 2008

Acquisitions" in the accompanying consolidated financial statements for a description of the February 2008 transaction with EnCana.

During the year ended December 31, 2009, negative revisions totaling 725.5 Bcfe were primarily related to the loss of Piceance Basin undeveloped reserves as a result of lower pricing from utilizing the 12-month historical average required by the new SEC rules for use in the December 31, 2009 reserve report and our more limited capital development plan at the time based on capital resources. The 2009 increase in proved reserves from extensions and discoveries totaling 20.4 Bcfe was primarily comprised of Rocky Mountain proved reserve increases primarily from our Piceance Basin drilling program and related offset wells. Also, during 2009, proved reserves totaling 3.5 Bcfe located in various states were sold in a series of transactions described in Note 4, "Oil and Gas Properties – Year Ended December 31, 2009 – Divestitures" in the accompanying consolidated financial statements.

During the year ended December 31, 2010, positive revisions totaling 14.5 Bcfe were primarily related to increased Piceance Basin proved reserves from the incorporation of improved fracturing technology, partially offset by Gulf Coast proved undeveloped reserves removed as a result of drilling plan modifications in conjunction with the Wapiti Transaction. The 2010 increase in extensions and discoveries of 22.2 Bcfe is primarily related to Piceance locations added as proved reserves in 2010 offset to wells previously drilled. Also, during 2010, proved reserves totaling 39.2 Bcfe located in Texas, Colorado, and Wyoming were sold in conjunction with the Wapiti Transaction described in Note 4, "Oil and Gas Properties – Year Ended December 31, 2010 – Divestitures."

Company Acquisitions, Divestitures and Financings

We plan to continue to evaluate potential acquisitions and property development opportunities, as well as divestitures of non-core assets. During the years ended December 31, 2008, 2009 and 2010, we completed the following transactions:

On February 20, 2008, we issued 36.0 million shares of common stock to Tracinda Corporation at $19.00 per share for gross proceeds of approximately $684 million. As a result of the transaction, subsequent purchases in the open market, and the May equity offering, Tracinda currently owns approximately 33% of our outstanding common stock.

On February 28, 2008, we closed a $410.1 million transaction with EnCana Oil & Gas (USA) Inc. ("EnCana") to jointly develop a portion of EnCana's leasehold interests in the Vega Area of the Piceance Basin. We acquired over 1,700 drilling locations on approximately 18,250 gross acres with a 95% working interest. The effective date of the transaction was March 1, 2008. The related agreement superseded a March 2007 agreement with EnCana and accordingly we have no further drilling commitment to EnCana under the March 2007 agreement.

In March 2008, DHS acquired three rigs and spare equipment for a purchase price of $23.3 million. The transaction was funded by the proceeds from two notes payable issued by DHS to Delta and Chesapeake of $6.0 million each and of proceeds of $6.0 million each from Delta and Chesapeake for additional shares of common stock issued by DHS. On August 15, 2008 the $6.0 million notes payable from both Delta and Chesapeake were converted into shares of DHS stock.

In July and August 2008, we completed several transactions to acquire unproved leasehold interests in two prospect areas. The total cost of the acquisitions was approximately $41.6 million. Pursuant to one of the agreements, we were obligated to drill an initial appraisal well by July 1, 2009 but due to our inability drill such well, in late May 2009, an amendment to the agreement was executed whereby the leases reverted to the original seller and we retained an option to participate in future transactions, if any, related to the leases contained in the area of mutual interest.

In August 2008, DHS acquired a 2,000 horsepower drilling rig with a 25,000 foot depth rating for a purchase price of $12.3 million (Rig #23). The acquisition was financed by an increase in the DHS credit facility.

On August 25, 2008, we completed an asset exchange agreement in which we acquired additional incremental interests in certain Midway Loop properties in exchange for $15.1 million in cash and non-core undeveloped properties in Divide Creek. The transaction resulted in a gain of $715,000 during the year ended December 31, 2008.

On September 15, 2008, we entered into an agreement with EnCana to acquire all of EnCana's net leasehold position and interest in wells in the Columbia River Basin of Washington and Oregon. The purchase price for the leasehold properties was $25.0 million and the transaction closed on September 26, 2008. On September 26, 2008, we completed a separate transaction related to the Columbia River Basin wherein we sold a 50% working interest participation in all of our Columbia River Basin leasehold interests and wells for cash consideration of $42.0 million plus one half of the drilling costs incurred to date on our well currently drilling in the area. This transaction included one half of the leasehold interests acquired from EnCana on September 15, 2008.

During the fourth quarter of 2009 through a series of transactions, we divested of certain non-operated properties in Alabama, California, Colorado, Louisiana, North Dakota, Oklahoma, Texas and Wyoming and certain non-strategic operated properties in Colorado and Wyoming for cash consideration of $4.7 million. In addition, we sold the amine unit from our Paradox Pipeline gas plant for $1.8 million and various pipe and tubular inventory for proceeds of $1.8 million. These transactions resulted in a combined loss of $5.7 million.

During the year ended December 31, 2010, we divested of our interests in certain non-core properties for gross proceeds of $980,000 and the assumption of plugging and abandonment obligations. Proved reserves attributable to these properties were insignificant.

On July 23, 2010, we entered into a definitive Purchase and Sale Agreement with Wapiti to sell all or a portion of our interest in various non-core assets primarily located in Colorado, Texas, and Wyoming for gross cash proceeds of $130.0 million resulting in a net loss of $66.5 million (including impairment losses of $96.2 million). For financial reporting purposes, a $4.0 million impairment loss is included within dry hole costs and impairments in continuing operations, $92.2 million of impairments are included within loss from discontinued operations, and a $29.7 million gain on sale is included in gain on sale of discontinued operations.

Discontinued Operations

In accordance with accounting standards, the results of operations and impairment loss relating to certain of the Wapiti Transaction properties have been reflected as discontinued operations. Properties associated with the Wapiti Transaction in which we only sold half of our interest continue to be reported as a component of continuing operations. The fields classified as discontinued operations are fields in which we sold all of our interest including the Garden Gulch field, Baffin Bay field, and Bull Canyon field as well as our interest in our wholly-owned subsidiary Piper Petroleum. In separate transactions, we sold our interests in the Howard Ranch and Laurel Ridge fields which are also included in discontinued operations.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements other than operating leases.

Contractual Obligations

Contractual Obligations at December 31, 2010	2011	2012 - 2013	2014 - 2015	Thereafter	Total
	For the years ending December 31,				
			(In thousands)		
Credit facility[1]	$ -	$ 29,130	$ -	$ -	$ 29,130
Installments payable on property acquisitions[2]		100,000	-	-	-
	100,000				
7% Senior unsecured notes	-	-	150,000	-	150,000
Interest on 7% Senior unsecured notes	10,500	21,000	13,125	-	44,625
3¾% Senior convertible notes[3]	-	115,000	-	-	115,000
Interest on 3¾% Senior convertible notes[3]	4,313	1,418	-	-	5,731
Credit facility – DHS[1]	69,590	-	-	-	69,590
Derivative liability	574	2,419	-	-	2,993
Abandonment retirement obligation	1,099	49	296	8,749	10,193
Operating leases	1,596	2,875	1,754	682	6,907
Total contractual cash obligations	$ 187,672	$171,891	$165,175	$ 9,431	$ 534,169

[1] Due to fluctuations in the credit facility balances and interest rates, interest payments have not been included.

[2] Amounts due will be funded with restricted cash deposits on hand.

[3] The convertible notes may be put to us by the holders of the notes on May 1, 2012, and accordingly, interest on these notes is reflected in the table above only through May 1, 2012.

Credit Facility

The MBL Credit Agreement matures on January 31, 2012. The revolving loan has an initial borrowing base of $30.0 million and bears interest at prime plus 6% per annum for prime rate advances and LIBOR plus 7% per annum for LIBOR advances. At December 31, 2010, $29.1 million was outstanding under the revolving loan. As a result of the first amendment entered into as of March 14, 2011, the commitment under the term loan increased from $20.0 million to $25.0 million. In addition, certain restrictions on the use of advances under the term loan were removed, as well as the requirement, so long as Delta is not in default under the MBL Credit Agreement, to repay any term loan advances outstanding on a monthly basis with 100% of net operating cash flow as was previously required. As amended, Advances under the term loan bear interest at prime plus 9.5% through September 30, 2011 and prime plus 11.0% thereafter for prime rate advances and at LIBOR plus 10.5% for LIBOR advances through September 30, 2011 and LIBOR plus 12% thereafter for LIBOR advances. Prior to the amendment, advances under the term loan bore interest at prime plus 8% per annum for prime rate advances and LIBOR plus 9% for LIBOR advances. At December 31, 2010, no amounts had been borrowed under the term loan. The revolving loan and the term loan are subject to quarterly financial covenants, in each case as defined in the MBL Credit Agreement and described in summary here, including maintenance of a minimum current ratio of 1:1, minimum quarterly net operating cash flow of $8.6 million, and maximum quarterly general and administrative expenses (excluding equity based compensation) of $5.0 million. In addition, we may not permit our trade payables to be outstanding more than 90 days following the receipt of applicable invoices. At December 31, 2010, we were in compliance with our financial covenants under the MBL Credit Agreement. See Note 20, "Subsequent Events" to the accompanying consolidated financial statements for a description of the first amendment.

The borrowing base for the revolving loan is subject to a semi-annual re-determination based on reserve reports as of each January 1 and July 1 as reported by us to MBL on or before each April 1 and October 1, respectively. The borrowing base is also subject to special redeterminations at the request of the lenders or if requested by us based on drilling success. If, as a result of any reduction in the amount of our borrowing base, the total amount of the outstanding debt were to exceed the amount of the borrowing base in effect, then, within 30 days after we are notified of the borrowing base deficiency, we would be required to (1) make a mandatory payment of principal to reduce our outstanding indebtedness so that it would not exceed our borrowing base, (2) eliminate the deficiency by making five equal monthly principal payments, (3) provide additional collateral for consideration to eliminate the deficiency within 30 days or (4) eliminate the deficiency through a combination of (1) through (3). If for any reason we were unable to pay the full amount of the mandatory prepayment within the requisite 30-day period, we would be in default of our obligations under the MBL Credit Agreement.

The MBL Credit Agreement includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, mergers and acquisitions, and includes various financial covenants.

Under certain conditions, amounts outstanding under the credit facility may be accelerated. Bankruptcy and insolvency events with respect to us or certain of our subsidiaries would result in an automatic acceleration of the indebtedness under the credit facility. Subject to notice and cure periods in certain cases, other events of default under the credit facility would result in acceleration of the indebtedness at the option of the lending banks. Such other events of default include non-payment, breach of warranty, non-performance of obligations under the credit facility (including financial covenants), default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, and a failure of the liens securing the credit facility.

This facility is secured by a first and prior lien to the lender on most of our oil and gas properties, certain related equipment, oil and gas inventory, and equity interests in unconsolidated affiliates.

Installments Payable on Property Acquisition

On February 28, 2008, we closed a transaction with EnCana to jointly develop a portion of EnCana's leasehold interests in the Vega Area of the Piceance Basin. Under the terms of the agreement we have committed to fund \$410.1 million, of which \$110.5 million was paid at the closing, \$99.6 million was paid on November 1, 2009, \$100 million was paid on November 1, 2010 and the remaining \$100 million balance is due November 1, 2011. The remaining installment is collateralized by a letter of credit, which in turn is collateralized by cash on deposit in a restricted account. The installment payment obligation is recorded in the accompanying consolidated financial statements as current liabilities at a discounted value, initially of \$280.1 million, based on an imputed interest rate of 2.58%. The discount is being accreted on the effective interest method over the term of the installments, including accretion of \$7.0 million and \$4.6 million for the years ended December 31, 2009 and 2010, respectively.

7% Senior Unsecured Notes, due 2015

On March 15, 2005, we issued 7% senior unsecured notes for an aggregate amount of \$150.0 million which pay interest semi-annually on April 1 and October 1 and mature in 2015 (the "Senior Notes"). The Senior Notes were issued at 99.50% of par and the associated discount is being amortized to interest expense over their term. The indenture governing the Senior Notes contains various restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, make certain investments, sell assets, consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries. These covenants may limit management's discretion in operating our business. In addition, in the event that a Change of Control should occur (as such term is defined in the indenture), each holder of the Senior Notes would have the right to require us to repurchase all or any part of such holder's notes at a purchase price in cash equal to 101% of the principal amount of the notes plus accrued and unpaid interest, if any, to the date of purchase.

3¾% Senior Convertible Notes, due 2037

On April 25, 2007, we issued \$115.0 million aggregate principal amount of 3¾% Senior Convertible Notes due 2037 (the "Notes") for net proceeds of \$111.6 million after underwriters' discounts and commissions of approximately \$3.4 million. The Notes bear interest at a rate of 3¾% per annum, payable semi-annually in arrears, on May 1 and November 1 of each year, beginning November 1, 2007. The Notes will mature on May 1, 2037 unless earlier converted, redeemed or repurchased, but each holder of Notes has the option to require us to purchase any outstanding Notes on each of May 1, 2012, May 1, 2017, May 1, 2022, May 1, 2027 and May 1, 2032 at a price which is required to be paid in cash, equal to 100% of the principal amount of the Notes to be purchased. The Notes will be convertible at the holder's option, in whole or in part, at an initial conversion rate of 32.9598 shares of common stock per \$1,000 principal amount of Notes (equivalent to a conversion price of approximately \$30.34 per share) at any time prior to the close of business on the business day immediately preceding the final maturity date of the Notes, subject to prior repurchase of the Notes. The conversion rate may be adjusted from time to time in certain instances. Upon conversion of a Note, we will have the option to deliver shares of our common stock, cash or a combination of cash and shares of our common stock for the Notes surrendered. In the event that a fundamental change occurs (as defined in the Indenture, but generally including a tender offer for a majority of our securities, an acquisition by anyone of 50% or more of our stock, a change in the majority of our Board of Directors, the approval of a plan of liquidation or being delisted from a national securities exchange), each holder of Notes would have the right to require us to purchase all or a portion of its Notes for the price specified in the Indenture. In addition, following certain fundamental changes that occur prior to maturity, we will increase the conversion rate for a holder who elects to convert their Notes in connection with such fundamental changes by a number of additional shares of common stock. Also, we are not permitted to consolidate with or merge with or into, or convey, transfer, sell, lease or dispose of all or substantially all of our assets unless the successor company meets certain requirements and assumes all of our obligations under the Notes. If as a result of such transaction, the Notes become convertible into common stock or other securities issued by another issuer, the other issuer must fully and unconditionally guarantee all of our obligations under the Notes. Although the Notes do not contain any financial covenants, the Notes contain covenants that require us to properly make payments of principal and interest, provide certain reports, certificates and notices to the trustee under various circumstances, cause our wholly-owned subsidiaries to become guarantors of the debt, maintain an office or agency where the Notes may be presented or surrendered for payment, continue our corporate existence, pay taxes and other claims, and not seek protection from the debt under any applicable usury laws.

Credit Facility – DHS

On April 1, 2010, DHS amended its existing credit facility with LCPI and renegotiated certain terms of the agreement including obtaining waivers for all covenant violations through March 31, 2010. The terms of the amended agreement required principal payments of approximately $7.7 million paid on April 1, 2010 and $2.0 million paid on each of May 1, 2010, August 1, 2010 and November 1, 2010, with a remaining $2.0 million principal payment due on January 1, 2011, and a $5.0 million principal payment due on each of April 1, 2011 and July 1, 2011 with the remaining balance of approximately $57.6 million due at maturity (August 31, 2011). In addition to the required payments, DHS may be required to prepay any remaining outstanding principal with the "Net Cash Proceeds from any Asset Sale," as defined by the credit facility, and any such prepayment shall be applied to, first, prepay the immediately succeeding Scheduled Installment in full, second, prepay all interest payable on the immediately succeeding Interest Payment Date in full, third, pay the second succeeding Scheduled Installment in full and fourth, prepay the remaining principal balance of the remaining loans. DHS is also required to prepay the principal amount of the loans in an amount equal to 75% of the "Excess Cash Flow," as defined by the credit facility, for such fiscal quarter. The financial covenants required in the DHS credit agreement include a minimum EBITDA covenant of $1.5 million for each quarter beginning December 31, 2010 and a capital expenditures limitation of $1.2 million for any fiscal quarter. Notwithstanding the $1.2 million per quarter limitation on capital expenditures, the amendment imposes aggregate capital expenditure limitations of $3.5 million for fiscal year 2010 and approximately $2.3 million for fiscal year 2011. The interest rate was adjusted to LIBOR plus 625 basis points, subject to a LIBOR floor rate of 2.75%. DHS was not in compliance with its minimum EBITDA covenant and quarterly capital expenditures limitation as of December 31, 2010. On January 1, 2011, DHS failed to pay its scheduled principal and interest payment and subsequently entered into a forbearance agreement more fully described in Note 20, "Subsequent Events" to the accompanying consolidated financial statements.

The credit facility matures on August 31, 2011 and the debt is classified as a current liability in the December 31, 2010 consolidated balance sheet. The DHS facility is non-recourse to Delta.

Other Contractual Obligations

Our asset retirement obligation arises from the costs necessary to plug and abandon our oil and gas wells. The majority of this obligation is not expected to occur during the next five years.

We lease our corporate office in Denver, Colorado under an operating lease which will expire in 2014. Our average yearly payments approximate $1.2 million over the remaining term of the lease. We have additional operating lease commitments which represent office equipment leases and lease obligations primarily relating to field vehicles and equipment.

We had a net derivative liability of $3.0 million at December 31, 2010. The ultimate settlement amounts of these derivative instruments are unknown because they are subject to continuing market fluctuations. See Item 3. "Quantitative and Qualitative Disclosures about Market Risk" for more information regarding our derivative instruments.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations were based on the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 3 to our consolidated financial statements. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas reserves, bad debts, oil and gas properties, marketable securities, income taxes, derivatives, contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe are reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements.

Successful Efforts Method of Accounting

We account for our natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within an oil and gas field are typically considered development costs and are capitalized, but often these seismic programs extend beyond the reserve area considered proved, and management must estimate the portion of the seismic costs to expense. The evaluation of gas and oil leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in hopes of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Reserve Estimates

Estimates of gas and oil reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future gas and oil prices, the availability and cost of capital to develop the reserves, future operating costs, severance taxes, development costs and workover gas costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our gas and oil properties and/or the rate of depletion of the gas and oil properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. At December 31, 2010, based on our more limited development plan given our current capital constraints, we were unable to book as proved reserves substantially all of our undeveloped locations in the Piceance Basin that would otherwise qualify as proved. In addition to obtaining adequate capital, further development of our Piceance Basin locations depends on higher commodity prices in the future, reductions in future drilling costs, improved recoveries or a combination of all three.

Impairment of Gas and Oil Properties

We review our oil and gas properties for impairment quarterly or whenever events and circumstances indicate a decline in the recoverability of their carrying value. We estimate the expected future cash flows of our developed proved properties and compare such future cash flows to the carrying amount of the proved properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and gas properties to their fair value. The primary factors used to determine fair value include estimates of proved reserves, future production estimates, future commodity pricing, anticipated capital expenditures and production costs, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected.

Given the complexities associated with gas and oil reserve estimates and the history of price volatility in the gas and oil markets, events may arise that would require us to record an impairment of the recorded book values associated with gas and oil properties. For developed properties, the review consists of a comparison of the carrying value of the asset with the asset's expected future undiscounted cash flows without interest costs. As a result of this assessment, during the year ended December 31, 2010, we recorded impairment provisions attributable to our proved and unproved properties and other items of $43.5 million which primarily included proved impairments to our Opossum Hollow and Golden Prairie fields of $1.1 million and unproved impairments of $30.0 million related to our Columbia River Basin leasehold, Hingeline leasehold, Haynesville leasehold, Delores River leasehold, Howard Ranch leasehold, and our non-operated Garden Gulch field in the Piceance Basin. Other impairments primarily included $6.7 million for the produced water handling facility in Vega and $4.9 million to reduce the Paradox pipeline carrying value to its estimated fair value.

In addition to the impairment provisions discussed above, we utilized various fair value techniques related to our Garden Gulch, Baffin Bay, DJ Basin, Caballos Creek, Opossum Hollow, Midway Loop, and Newton fields, as well as our interest in our wholly owned subsidiary Piper Petroleum and unproved acreage positions in the DJ Basin and South Texas assets which were held for sale at June 30, 2010 and determined that impairment provisions of $93.2 million related to proved properties and $3.0 million related to unproved properties were required to be recognized during the three months ended June 30, 2010. Based upon the applicable accounting standards, $4.0 million of the impairment provision is included within dry hole costs and impairments in the accompanying statement of operations for the year ended December 31, 2010 and $92.2 million is included in loss from discontinued operations for the year ended December 31, 2010.

In 2009, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $143.3 million primarily related to our non-operated Garden Gulch field in the Piceance Basin of $38.6 million, Haynesville Shale of $27.5 million, Columbia River Basin of $21.4 million, Lighthouse Bayou of $14.8 million, proved and unproved impairments in various Gulf Coast fields of $18.5 million, Vega surface land of $10.5 million, proved and unproved impairments in various Rockies fields of $5.4 million, pipe and tubular inventory of $4.3 million and Paradox pipeline of $1.9 million.

In 2008, we recorded impairment provisions related to continuing operations attributable to our proved and unproved properties totaling approximately $277.7 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas of $192.5 million, Paradox field in Utah of $30.5 million, Howard Ranch and Bull Canyon fields in the Rockies of $4.1 million, Utah Hingeline of $40.8 million and our offshore California field of $9.8 million. The impairments were primarily due to the significant decline in commodity pricing during the fourth quarter of 2008. In addition, we recorded impairments to our Paradox pipeline of $21.5 million, certain DHS rigs of $21.6 million and we wrote off DHS's goodwill of $7.7 million.

For fiscal year 2011, we are continuing to develop and evaluate certain proved and unproved properties on which favorable or unfavorable results or commodity prices may cause us to revise in future quarters our estimates of those properties' estimated future cash flows or fair value. Such revisions of estimates could require us to record an impairment in the period of such revisions.

Commodity Derivative Instruments and Hedging Activities

We may periodically enter into commodity derivative contracts or fixed-price physical contracts to manage our exposure to oil and natural gas price volatility. We primarily utilize futures contracts, swaps or options, which are generally placed with major financial institutions or with counterparties of high credit quality that we believe represent minimal credit risks.

All derivative instruments are recorded on the balance sheet at fair value which must be estimated using complex valuation models. We recognize mark-to-market gains and losses in current earnings instead of deferring those amounts in accumulated other comprehensive income.

As of December 31, 2010, we had a total of five oil and gas derivative contracts outstanding. The fair value of our oil derivative instruments was a liability of $6.6 million and the fair value of our gas derivative instruments was an asset of $3.6 million at December 31, 2010. We classify the fair value amounts of derivative assets and liabilities executed under master netting arrangements as net derivative assets or net derivative liabilities, whichever the case may be, by commodity and master netting counterparty. The discount rates used to determine the fair value of these derivative instruments include a measure of non-performance risk by both Delta and the counterparty, and accordingly, the liability reflected is less than the actual cash expected to be paid upon settlement based on forward strip prices as of December 31, 2010. The pre-credit risk adjusted fair value of our net derivative liabilities as of December 31, 2010 was $4.5 million. A credit risk adjustment of $1.5 million to the fair value of the derivatives reduced the reported amount of the net derivative liabilities on our consolidated balance sheet to $3.0 million.

Asset Retirement Obligation

We account for our asset retirement obligations under applicable FASB guidance which requires entities to record the fair value of a liability for retirement obligations of acquired assets. Our asset retirement obligations arise from the plugging and abandonment liabilities for our oil and gas wells. The fair value is estimated based on a variety of assumptions including discount and inflation rates and estimated costs and timing to plug and abandon wells.

Deferred Tax Asset Valuation Allowance

We use the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the estimated future tax effects attributable to temporary differences and carryforwards. Ultimately, realization of a deferred tax benefit depends on the existence of sufficient taxable income within the carryback/carryforward period to absorb future deductible temporary differences or a carryforward. In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. As a result of management's current assessment, we maintain a significant valuation allowance against our deferred tax assets. We will continue to monitor facts and circumstances in our reassessment of the likelihood that operating loss carryforwards and other deferred tax attributes will be utilized prior to their expiration. As a result, we may determine that the deferred tax asset valuation allowance should be increased or decreased. Such changes would impact net income through offsetting changes in income tax expense or benefit.

Recently Issued Accounting Pronouncements

Applicable recently issued accounting pronouncements have been adopted as of December 31, 2010.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Market Rate and Price Risk

We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, which may from time to time include costless collars, swaps, or puts. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy. We use hedges to provide a measure of stability and predictability to our future revenues and cash flows in an environment of volatile oil and gas prices. We also may use hedges in conjunction with acquisitions to achieve expected economic returns during the payout period.

The following table summarizes our open derivative contracts at December 31, 2010:

Commodity	Volume		Fixed Price	Term		Index Price	Net Fair Value Asset (Liability) at December 31, 2010 (In thousands)
Crude oil	500	Bbls / Day	$ 57.70	Jan '11	- Dec '11	NYMEX – WTI	(5,946)
Crude oil	116	Bbls / Day	$ 91.05	Jan '11	- Dec '11	NYMEX – WTI	(70)
Crude oil	497	Bbls / Day	$ 91.05	Jan '12	- Dec '12	NYMEX – WTI	(408)
Crude oil	396	Bbls / Day	$ 91.05	Jan '13	- Dec '13	NYMEX – WTI	(181)
Natural gas	12,000	MMBtu / Day	$ 5.150	Jan '11	- Dec '11	CIG	4,337
Natural gas	3,253	MMBtu / Day	$ 5.040	Jan '11	- Dec '11	CIG	1,047
Natural gas	347	MMBtu / Day	$ 4.440	Jan '11	- Dec '11	CIG	58
Natural gas	12,052	MMBtu / Day	$ 4.440	Jan '12	- Dec '12	CIG	(771)
Natural gas	10,301	MMBtu / Day	$ 4.440	Jan '13	- Dec '13	CIG	(1,059)
Total							$ (2,993)

Assuming production and the percent of oil and gas sold remained unchanged from the year ended December 31, 2010 a hypothetical 10% decline in the average market price we realized during the year ended December 31, 2010 on unhedged production would reduce our oil and natural gas revenues by approximately $9.5 million on an annual basis.

In January and February 2011, we entered into natural gas liquids derivative contracts that established a set commodity price for the hedged portion of our anticipated production as shown below:

		2011		2012		2013	
Commodity	Index Price	Volume (Mgl)	Price	Volume (Mgl)	Price	Volume (Mgl)	Price
Isobutane	Mont Belvieu-OPIS	659	$ 1.61	559	$ 1.52	224	$ 1.44
Normal Butane	Mont Belvieu-OPIS	790	1.56	671	1.49	269	1.41
Natural Gasoline	Mont Belvieu-OPIS	1,317	2.06	1,118	2.02	448	1.93
Propane	Mont Belvieu-OPIS	2,897	1.18	2,459	1.08	987	0.98
Purity Ethane	Mont Belvieu-OPIS	7,507	0.48	6,370	0.40	2,556	0.36
Total		13,170	$ 0.91	11,177	$ 0.83	4,484	$ 0.77

Interest Rate Risk

We were subject to interest rate risk on $98.7 million of variable rate debt obligations at December 31, 2010. The annual effect of a 10% change in interest rates would be approximately $0.8 million. The interest rate on these variable debt obligations approximates current market rates as of December 31, 2010.

As of December 31, 2010, we have fixed rate debt totaling $258.3 million. The fair value of the fixed rate debt as of December 31, 2010 was approximately $203.0 million.

Item 8. Financial Statements and Supplementary Data

Financial Statements are included and begin on page F-1. There are no financial statement schedules since they are either not applicable or the information is included in the notes to the financial statements.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

Not applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and that such information is accumulated and communicated to management, including the chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure. Management necessarily applied its judgment in assessing the costs and benefits of such controls and procedures, which, by their nature, can provide only reasonable assurance regarding management's control objectives.

With the participation of management, our principal executive officer and principal financial officer evaluated the effectiveness of the design and operation of our disclosure controls and procedures at the conclusion of the period ended December 31, 2010. Based upon this evaluation, the principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for Delta. As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Exchange Act), internal control over financial reporting is a process designed by, or under the supervision of, our principal executive and principal financial officers and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles.

Our internal control over financial reporting is supported by written policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In connection with the preparation of our annual consolidated financial statements, management has undertaken an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2010, our internal control over financial reporting was effective.

KPMG LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this report, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2010.

Changes in Internal Controls

There were no changes in internal control over financial reporting that occurred during the fourth quarter of 2010 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

As previously reported, on December 29, 2010, we entered into the MBL Credit Agreement, which provides for a revolving loan and a term loan each with a maturity date of January 31, 2012. The revolving loan has an initial borrowing base of $30.0 million and the term loan had an initial commitment of $20.0 million subject to a development plan that must be approved by MBL.

On March 14, 2011, we entered into an amendment to the MBL Credit Agreement (the "First Amendment") that increased the availability under the term loan at the time from $6.2 million to $25.0 million, and doesn't require repayments of the term loan until the January 2012 maturity date. Specifically, among other changes, the amendment provided for an increase in the term loan commitment from $20.0 million to $25.0 million and removed the requirement that advances under the term loan be subject to approval of a development plan. In addition, so long as Delta is not in default under the MBL Credit Agreement, Delta is not required to comply with certain cash management provisions, including the previous requirement to repay any term loan advances outstanding on a monthly basis with 100% of net operating cash flows. In connection with the First Amendment, the interest rates for term loan advances increased to prime plus 9.5% through September 30, 2011 and prime plus 11.0% thereafter for prime rate advances and LIBOR plus 10.5% for LIBOR advances through September 30, 2011 and LIBOR plus 12% thereafter for LIBOR advances.

The foregoing description of the First Amendment does not purport to be complete and is qualified in its entirety by reference to the First Amendment, which is filed as Exhibit 10.25 hereto and incorporated by reference herein.

PART III

The information required by Part III, Item 10 "Directors and Executive Officers and Corporate Governance," Item 11 "Executive Compensation," Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," Item 13 "Certain Relationships and Related Transactions, and Director Independence" and Item 14 "Principal Accounting Fees and Services" is incorporated by reference to our definitive Proxy Statement which will be filed with the Securities and Exchange Commission in connection with the 2011 Annual Meeting of Stockholders. For certain information concerning Item 10 "Directors, Executive Officers and Corporate Governance," see Item 4A in Part I – "Directors and Executive Officers."

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements.

(a)(2) Financial Statement Schedules. None.

(a)(3) Exhibits. The Exhibits listed in the Index to Exhibits appearing at page 63 are filed as part of this report. Management contracts and compensatory plans required to be filed as exhibits are marked with a "*".

INDEX TO EXHIBITS

3.1 Certificate of Incorporation of the Company, as amended. Incorporated by reference to Exhibit 3.1 to our Form 8-K filed December 24, 2009.

3.2 Amended and Restated By-laws of the Company. Incorporated by reference to Exhibit 3.1 to our Form 8-K filed February 13, 2006.

4.1 Purchase Agreement dated March 9, 2005, among Delta Petroleum Corporation, the Guarantors named therein and the Initial Purchasers named therein. Incorporated by reference to Exhibit 4.1 to our Form 8-K filed March 21, 2005.

4.2 Registration Rights Agreement dated March 15, 2005, among Delta Petroleum Corporation, the Guarantors named therein and the Initial Purchasers named therein. Incorporated by reference to Exhibit 4.2 to our Form 8-K filed March 21, 2005.

4.3 Indenture dated as of March 15, 2005, among Delta Petroleum Corporation, the Guarantors named therein and US Bank National Association, as Trustee. Incorporated by reference to Exhibit 4.3 to our Form 8-K filed March 21, 2005.

4.4 Form of 7% Series A Senior Notes due 2015 with attached notation of Guarantees. Incorporated by reference to Exhibit 4.3 to our Form 8-K filed March 21, 2005.

4.5 Indenture, dated as of April 25, 2007, by and between our and the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (including Form of $3^3/_4$% Convertible Senior Note due 2037). Incorporated by reference to Exhibit 4.1 to our Form 8-K filed April 25, 2007.

4.6 Form of $3^3/_4$% Convertible Senior Note due 2037. Incorporated by reference to Exhibit 4.2 to our Form 8-K filed April 25, 2007.

10.1 Delta Petroleum Corporation 1993 Incentive Plan. Incorporated by reference to Exhibit 28.1 to our Form 8-K filed May 21, 1993.*

10.2 Delta Petroleum Corporation 1993 Incentive Plan, as amended June 30, 1999. Incorporated by reference to our Definitive Proxy Statement filed May 21, 1999.*

10.3 Delta Petroleum Corporation 2001 Incentive Plan. Incorporated by reference to Exhibit B to our Definitive Proxy Statement filed June 30, 2001.*

10.4 Delta Petroleum Corporation 2002 Incentive Plan. Incorporated by reference to Exhibit A to our Definitive Proxy Statement filed May 1, 2002.*

10.5 Delta Petroleum Corporation 2004 Incentive Plan. Incorporated by reference to Appendix B to our Definitive Proxy Statement filed November 22, 2004.*

10.6 Amendment No. 1 to Delta Petroleum Corporation 2004 Incentive Plan. Incorporated by reference to Exhibit 10.2 to our Form 8-K filed June 22, 2005.*

10.7 Delta Petroleum Corporation 2005 New-Hire Equity Incentive Plan. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed June 22, 2005.*

10.8 Delta Petroleum Corporation 2006 New-Hire Equity Incentive Plan. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed June 26, 2006.*

10.9 Delta Petroleum Corporation 2007 Performance and Equity Incentive Plan. Incorporated by reference to Appendix A to our Definitive Proxy Statement filed December 28, 2006.*

10.10 Delta Petroleum Corporation 2009 Performance and Equity Incentive Plan. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed December 24, 2009. *

10.11 Delta Petroleum Corporation 2008 New-Hire Equity Incentive Plan. Incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q filed August 7, 2008.*

10.12 Form of restricted stock award agreement for awards under the Delta Petroleum Corporation 2009 Performance and Equity Incentive Plan. Incorporated by reference to Exhibit 10.12 to our Form 10-K for the year ended December 31, 2009 and filed March 12, 2010.*

10.13 Amended and Restated Employment Agreement with Carl Lakey dated July 15, 2010. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed July 21, 2010.

10.14 Employment Agreement with Kevin K. Nanke dated May 5, 2005. Incorporated by reference to Exhibit 10.2 to our Form 8-K filed May 11, 2005.*

10.15 Employment Agreement with Stanley F. Freedman dated January 11, 2006. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed January 12, 2006.*

10.16 Change in Control Executive Severance Agreement with Carl Lakey dated October 1, 2009. Filed herewith electronically.*

10.17 Change in Control Executive Severance Agreement with Kevin K. Nanke dated April 30, 2007. Incorporated by reference to Exhibit 10.3 to our Form 8-K filed May 2, 2007.*

10.18 Change in Control Executive Severance Agreement with Stanley F. Freedman dated April 30, 2007. Incorporated by reference to Exhibit 10.4 to our Form 8-K filed May 2, 2007.*

10.19 Amendment to Amended and Restated Employment Agreement and Change-in-Control Employee Severance Agreement, dated December 29, 2010, among Delta Petroleum Corporation and Carl Lakey. Incorporated by reference to Exhibit 10.2 to our Form 8-K filed January 5, 2011.*

10.20 Amendment to Employment Agreement and Change-in-Control Executive Severance Agreement, dated December 29, 2010, among Delta Petroleum Corporation and Kevin Nanke. Incorporated by reference to Exhibit 10.3 to our Form 8-K filed January 5, 2011.*

10.21 Amendment to Employment Agreement and Change-in-Control Executive Severance Agreement, dated December 29, 2010, among Delta Petroleum Corporation and Stanley Freedman. Incorporated by reference to Exhibit 10.4 to our Form 8-K filed January 5, 2011.*

10.22 Severance Agreement by and between Delta Petroleum Corporation and Roger Parker, dated May 26, 2009. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed June 1, 2009.*

10.23 Severance Agreement by and between Delta Petroleum Corporation and John R. Wallace, effective October 19, 2010. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed October 25, 2010.*

10.24 Third Amended and Restated Credit Agreement, dated December 29, 2010, among Delta Petroleum Corporation, the lenders party thereto, and Macquarie Bank Limited, as administrative agent and as issuing lender. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed January 5, 2011.

10.25 First Amendment to Third Amended and Restated Credit Agreement, dated March 14, 2011, among Delta Petroleum Corporation, the lenders party thereto, and Macquarie Bank Limited, as administrative agent and as issuing lender. Filed herewith electronically.

10.26 Amended and Restated Credit Agreement dated as of August 15, 2008, among DHS Holding Company, DHS Drilling Company, the several banks and other financial institutions or entities from time to time parties to such Agreement, Lehman Brothers, Inc. as sole arranger and sole bookrunner and Lehman Commercial Paper, Inc. as syndication agent. Incorporated by reference to Exhibit 10.3 to our Form 10-Q for the quarterly period ended September 30, 2008 and filed November 6, 2008.

10.27 Amendment Number One to Amended and Restated Credit Agreement dated effective September 19, 2008, among DHS Holding Company, DHS Drilling Company, the several banks and other financial institutions or entities from time to time parties to such Agreement, Lehman Brothers, Inc. as sole arranger and sole bookrunner and Lehman Commercial Paper, Inc. as syndication agent. Incorporated by reference to Exhibit 10.4 to our Form 10-Q for the quarterly period ended September 30, 2008 and filed November 6, 2008.

10.28 Carry and Earning Agreement dated February 28, 2008 between the Company and EnCana Oil & Gas (USA) Inc. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed March 5, 2008.

10.29 Forbearance Agreement dated as of April 22, 2009 among DHS Holding Company, DHS Drilling Company and Lehman Commercial Paper, Inc. under that certain Amended and Restated Credit Agreement dated as of August 15, 2008, as amended by that certain Amendment No. 1, dated as of September 19, 2008. Incorporated by reference to Exhibit 10.3 to our Form 10-Q for the quarterly period ended March 31, 2009 and filed May 5, 2009.

10.30 Waiver and Amendment No. 2 to Amended and Restated Credit Agreement, dated as of April 1, 2010, among DHS Holding Company and Lehman Commercial Paper, Inc. Incorporated by reference to Exhibit 10.1 to our Form 10-Q filed May 10, 2010.

10.31 Agreement between Delta Petroleum Corporation and Amber Resources Company dated July 1, 2001. Incorporated by reference to Exhibit 10.3 to our Form 8-K filed December 20, 2001.

10.32 Company Stock Purchase Agreement, dated December 29, 2007, by and between Delta Petroleum Corporation and Tracinda Corporation. Incorporated by reference to Exhibit 1.1 to our Form 8-K filed January 25, 2008.

10.33 Purchase and Sale Agreement dated September 15, 2008 between the Company and EnCana Oil & Gas (USA) Inc. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed October 2, 2008.

10.34 Sale Agreement dated August 19, 2008 between the Company and Husky Refining Company. Incorporated by reference to Exhibit 10.2 to our Form 8-K filed October 2, 2008.

10.35 Purchase and Sale Agreement, dated as of July 23, 2010, by and between Delta Petroleum Corporation and Wapiti Oil & Gas, L.L.C. Incorporated by reference to Exhibit 10.1 to our Form 8-K filed July 27, 2010.

10.36 Forbearance Agreement dated as of December 31, 2010 among DHS Holding Company, DHS Drilling Company and Lehman Commercial Paper, Inc. under that certain Amended and Restated Credit Agreement dated as of August 15, 2008, as amended by that certain Amendment No. 1, dated as of September 19, 2008, and further amended by that certain Waiver and Amendment No. 2, dated as of April 1, 2010. Filed herewith electronically.

10.37 Forbearance Agreement No. 2 dated as of February 1, 2011 among DHS Holding Company, DHS Drilling Company and Lehman Commercial Paper, Inc. under that certain Amended and Restated Credit Agreement dated as of August 15, 2008, as amended by that certain Amendment No. 1, dated as of September 19, 2008, and further amended by that certain Waiver and Amendment No. 2, dated as of April 1, 2010. Filed herewith electronically.

10.38 Amended and Restated Forbearance Agreement No. 2 dated as of March 15, 2011 among DHS Holding Company, DHS Drilling Company and Lehman Commercial Paper, Inc. under that certain Amended and Restated Credit Agreement dated as of August 15, 2008, as amended by that certain Amendment No. 1, dated as of September 19, 2008, and further amended by that certain Waiver and Amendment No. 2, dated as of April 1, 2010. Filed herewith electronically.

21.1 Subsidiaries of the Registrant. Filed herewith electronically.

23.1 Consent of KPMG LLP. Filed herewith electronically.

23.2 Consent of Ralph E. Davis Associates, Inc. Filed herewith electronically.

31.1 Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. Filed herewith electronically.

31.2 Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. Filed herewith electronically.

32.1 Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 350. Filed herewith electronically.

32.2 Certification of Chief Financial Officer Pursuant to 18 U.S.C. Section 1350. Filed herewith electronically.

99.1 Report of Ralph E. Davis Associates, Inc. regarding the registrants Proved Reserves as of December 31, 2010. Filed herewith electronically.

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* Management contracts and compensatory plans.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Delta Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Delta Petroleum Corporation and subsidiaries as of December 31, 2010, and 2009, and the related consolidated statements of operations, changes in stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Delta Petroleum Corporation and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in note 2 to the consolidated financial statements, due to continued losses and limited borrowing capacity the Company is evaluating sources of capital to fund the Company's near term debt obligations. There can be no assurances that actions undertaken will be sufficient to repay obligations under the credit facility when due, which raises substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Delta Petroleum Corporation's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 16, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Denver, Colorado
March 16, 2011

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Delta Petroleum Corporation:

We have audited Delta Petroleum Corporation's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Delta Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Delta Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Delta Petroleum as of December 31, 2010 and 2009, and the related consolidated statements of operations, changes in stockholders' equity and comprehensive income (loss), and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated March 16, 2011 expressed an unqualified opinion on those consolidated financial statements. Our report contains an explanatory paragraph that states that due to continued losses and limited borrowing capacity the Company is evaluating sources of capital and that such actions may not be sufficient to repay debt obligations when due, which raises substantial doubt about its ability to continue as a going concern.

/s/ KPMG LLP

Denver, Colorado
March 16, 2011

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,653	$ 61,918
Short-term restricted deposits	100,000	100,000
Trade accounts receivable, net of allowance for doubtful accounts of $2,348 and $100, respectively	20,446	16,654
Deposits and prepaid assets	1,720	3,103
Inventories	3,446	5,588
Other current assets	5,541	5,189
Total current assets	146,806	192,452
Property and equipment:		
Oil and gas properties, successful efforts method of accounting:		
Unproved	230,117	280,844
Proved	871,986	1,379,920
Drilling and trucking equipment	174,680	177,762
Pipeline and gathering systems	93,558	92,064
Other	15,639	16,154
Total property and equipment	1,385,980	1,946,744
Less accumulated depreciation and depletion	(517,414)	(800,501)
Net property and equipment	868,566	1,146,243
Long-term assets:		
Long-term restricted deposit	-	100,000
Investments in unconsolidated affiliates	3,377	7,444
Deferred financing costs	1,832	3,017
Other long-term assets	3,531	8,329
Total long-term assets	8,740	118,790
Total assets	$ 1,024,112	$ 1,457,485
LIABILITIES AND EQUITY		
Current liabilities:		
Credit facility – DHS	$ 69,590	$ 83,268
Installments payable on property acquisition	97,874	97,874
Accounts payable	36,185	44,225
Offshore litigation payable	-	13,877
Other accrued liabilities	14,539	13,459
Derivative instruments	574	19,497
Total current liabilities	218,762	272,200
Long-term liabilities:		
Installments payable on property acquisition, net of current portion	-	95,381
7% Senior notes	149,684	149,609
3¾% Senior convertible notes	108,593	104,008
Credit facility - Delta	29,130	124,038
Asset retirement obligations	3,929	7,654
Derivative instruments	2,419	7,475
Total long-term liabilities	293,755	488,165
Commitments and contingencies		
Equity:		
Preferred stock, $0.01 par value: authorized 3,000,000 shares, none issued	-	-
Common stock, $0.01 par value; authorized 600,000,000 shares, issued 285,138,000 shares at December 31, 2010 and 282,548,000 shares at December 31, 2009	2,851	2,825
Additional paid-in capital	1,633,217	1,625,035
Treasury stock at cost; 33,000 shares at December 31, 2010 and 42,000 shares at December 31, 2009	(279)	(268)
Accumulated deficit	(1,121,342)	(939,010)
Total Delta stockholders' equity	514,447	688,582
Non-controlling interest	(2,852)	8,538
Total equity	511,595	697,120
Total liabilities and equity	$ 1,024,112	$ 1,457,485

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2010	2009	2008
	(In thousands, except per share amounts)		
Revenue:			
Oil and gas sales	$ 94,388	$ 82,723	$ 192,815
Contract drilling and trucking fees	53,212	13,680	49,445
Gain on offshore litigation settlement, net of loss on property sales	(795)	73,800	-
Total revenue	146,805	170,203	242,260
Operating expenses:			
Lease operating expense	24,566	26,439	27,896
Transportation expense	15,211	10,057	7,925
Production taxes	3,727	3,032	11,185
Exploration expense	1,337	2,604	10,975
Dry hole costs and impairments	43,572	176,871	411,103
Depreciation, depletion, amortization and accretion – oil and gas	58,265	81,335	80,218
Drilling and trucking operating expenses	42,248	15,293	32,594
Goodwill and drilling equipment impairments	-	6,508	29,349
Depreciation and amortization – drilling and trucking	19,964	22,917	14,134
General and administrative expense	41,130	41,414	53,607
Executive severance expense, net	(674)	3,739	-
Total operating expenses	249,346	390,209	678,986
Operating loss	(102,541)	(220,006)	(436,726)
Other income and (expense):			
Interest expense and financing costs, net	(37,247)	(52,581)	(35,357)
Other income (expense)	(1,409)	1,049	(5,210)
Realized gain (loss) on derivative instruments, net	(5,835)	(1,115)	18,383
Unrealized gain (loss) on derivative instruments, net	23,979	(26,972)	3,365
Income (loss) from unconsolidated affiliates	1,738	(15,473)	3,375
Total other expense	(18,774)	(95,092)	(15,444)
Loss from continuing operations before income taxes and discontinued operations	(121,315)	(315,098)	(452,170)
Income tax expense (benefit)	543	215	(11,723)
Loss from continuing operations	(121,858)	(315,313)	(440,447)
Discontinued operations:			
Loss from results of operations and sale of discontinued operations, net of tax	(72,156)	(34,371)	(27,103)
Net loss	(194,014)	(349,684)	(467,550)
Less net loss attributable to non-controlling interest	11,682	20,901	11,486
Net loss attributable to Delta common stockholders	$ (182,332)	$ (328,783)	$ (456,064)
Amounts attributable to Delta common stockholders:			
Loss from continuing operations	$ (110,176)	$ (294,412)	$ (428,961)
Loss from discontinued operations, net of tax	(72,156)	(34,371)	(27,103)
Net loss	$ (182,332)	$ (328,783)	$ (456,064)
Basic loss attributable to Delta common stockholders per common share:			
Loss from continuing operations	$ (0.40)	$ (1.40)	$ (4.49)
Discontinued operations	(0.26)	(0.16)	(0.28)
Net loss	$ (0.66)	$ (1.56)	$ (4.77)
Diluted loss attributable to Delta common stockholders per common share:			
Loss from continuing operations	$ (0.40)	$ (1.40)	$ (4.49)
Discontinued operations	(0.26)	(0.16)	(0.28)
Net loss	$ (0.66)	$ (1.56)	$ (4.77)

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)

(In thousands)

	Common stock Shares	Common stock Amount	Additional paid-in capital	Treasury stock Shares	Treasury stock Amount	Accumulated Other Comprehensive Income (Loss)	Accumulated Deficit	Total Delta Stockholders' Equity	Non-Controlling Interests	Total Equity	Comprehensive Income (Loss)
Balance, December 31, 2007	66,429	$ 664	$ 686,354	-	$ -	$ -	$ (154,163)	$ 532,855	$ 27,296	$ 560,151	
Comprehensive income:											
Net loss	-	-	-	-	-	-	(456,064)	(456,064)	(11,486)	(467,550)	$(467,550)
Other comprehensive income transactions, net of tax											
Change in fair value of available for sale securities	-	-	-	-	-	(4,589)	-	(4,589)	-	(4,589)	(4,589)
Loss on impairment of available for sale securities reclassified to earnings	-	-	-	-	-	4,589	-	4,589	-	4,589	4,589
Comprehensive loss											$(467,550)
Contributions to non-controlling interests	-	-	-	-	-	-	-	-	13,294	13,294	
Treasury stock acquired by subsidiary	-	-	-	36	(540)	-	-	(540)	-	(540)	
Shares issued for cash, net of offering costs	36,263	363	666,680	-	-	-	-	667,043	-	667,043	
Shares issued for cash upon exercise of options	540	5	4,822	-	-	-	-	4,827	-	4,827	
Issuance of non-vested stock	1,089	11	(11)	-	-	-	-	-	-	-	
Shares repurchased for withholding taxes	(147)	(1)	(1,368)	-	-	-	-	(1,369)	-	(1,369)	
Cancellation of executive performance shares, tranches 4 and 5	(750)	(8)	8	-	-	-	-	-	-	-	
Stock based compensation	-	-	15,638	-	-	-	-	15,638	-	15,638	
Balance, December 31, 2008	103,424	$ 1,034	$ 1,372,123	36	$ (540)	$ -	$ (610,227)	$ 762,390	$ 29,104	$ 791,494	
Comprehensive income:											
Net loss	-	-	-	-	-	-	(328,783)	(328,783)	(20,901)	(349,684)	$(349,684)
Comprehensive loss											$(349,684)
Treasury stock acquired by subsidiary	-	-	-	12	(47)	-	-	(47)	47	-	
Shares issued for cash, net of offering costs	172,500	1,725	245,180	-	-	-	-	246,905	-	246,905	
Issuance of non-vested stock	6,763	68	(69)	(16)	248	-	-	247	(247)	-	
Forfeitures of non-vested stock	(100)	(1)	1	-	-	-	-	-	-	-	
Shares repurchased for withholding taxes	(159)	(2)	(311)	10	71	-	-	(242)	(195)	(437)	
Cancellation of executive performance shares, tranches 4 and 5	(500)	(5)	5	-	-	-	-	-	-	-	
Cancellation of restricted shares due to reductions in force	(195)	(2)	2	-	-	-	-	-	-	-	
Executive severance – issuance	1,000	10	1,690	-	-	-	-	1,700	-	1,700	
Executive severance – forfeiture	(185)	(2)	(2,817)	-	-	-	-	(2,819)	-	(2,819)	
Stock based compensation	-	-	9,231	-	-	-	-	9,231	730	9,961	
Balance, December 31, 2009	282,548	$ 2,825	$ 1,625,035	42	$ (268)	$ -	$ (939,010)	$ 688,582	$ 8,538	$ 697,120	
Comprehensive income:											
Net loss	-	-	-	-	-	-	(182,332)	(182,332)	(11,682)	(194,014)	$(194,014)
Comprehensive loss											$(194,014)
Issuance of non-vested stock	5,653	56	95	(14)	104	-	-	255	(247)	8	
Forfeitures of non-vested stock	(2,150)	(21)	21	-	-	-	-	-	-	-	
Shares repurchased for withholding taxes	(913)	(9)	(737)	5	(115)	-	-	(861)	-	(861)	
Executive severance – forfeiture	-	-	(2,274)	-	-	-	-	(2,274)	-	(2,274)	
Stock based compensation	-	-	11,077	-	-	-	-	11,077	539	11,616	
Balance, December 31, 2010	285,138	$ 2,851	$ 1,633,217	33	$ (279)	$ -	$(1,121,342)	$ 514,447	$ (2,852)	$ 511,595	

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash flows from operating activities:			
Net loss	$ (194,014)	$ (349,684)	$ (467,550)
Adjustments to reconcile net loss to cash provided by operating activities:			
Basis in offshore properties recovered through litigation	-	17,904	-
Loss on sale of drilling, trucking and other assets	1,547	(1,156)	-
Loss on sale of oil and gas properties	-	5,655	-
Gain on sale of discontinued operations	(28,184)	-	(718)
Depreciation, depletion, and amortization – oil and gas	58,265	81,335	80,218
Depreciation and amortization – drilling and trucking	19,964	22,917	14,134
Depreciation, depletion, and amortization – discontinued operations	13,842	27,170	18,907
Dry hole costs and impairments	43,572	176,871	411,103
Impairments – discontinued operations	92,162	12,201	27,860
Goodwill and drilling equipment impairment	-	6,508	29,349
Stock based compensation	11,467	9,961	16,116
Executive severance payable in common stock	-	1,700	-
Executive severance – stock-based awards forfeited	(2,274)	(2,820)	-
Amortization of deferred financing costs	9,148	12,151	9,316
Accretion of discount on installments payable	4,619	7,038	6,082
Increase in allowance for bad debt	1,437	-	-
Unrealized (gain) loss on derivative contracts	(23,979)	26,972	(3,365)
(Gain) on marketable securities	(300)	(53)	4,590
(Income) loss from unconsolidated affiliates	(1,738)	15,809	(2,909)
Deferred income tax expense (benefit)	610	215	(11,789)
Other	1,043	(66)	127
Net changes in operating assets and liabilities:			
(Increase) decrease in trade accounts receivable	(6,849)	13,913	1,337
(Increase) decrease in deposits and prepaid assets	(511)	5,216	(7,381)
(Increase) decrease in inventories	(175)	(1,225)	(2,922)
(Increase) decrease in other current assets	423	(1,639)	(114)
Increase (decrease) in accounts payable	(19,199)	(18,924)	17,590
Increase (decrease) in offshore litigation payable	(13,877)	13,877	-
Increase (decrease) in other accrued liabilities	1,463	(702)	695
Net cash provided by (used in) operating activities	(31,538)	81,144	140,676
Cash flows from investing activities:			
Additions to property and equipment	(41,639)	(165,855)	(457,947)
Acquisitions, net of cash acquired	-	-	(221,815)
Proceeds from sale of oil and gas properties	132,945	8,393	42,000
Proceeds from sale of drilling assets and other fixed assets	665	9,111	3,201
Proceeds from sale of marketable securities	300	2,030	-
(Increase) decrease in restricted deposit	100,000	100,000	(300,000)
Additions to drilling and trucking equipment	(2,549)	(1,785)	(52,970)
Minority interest holder contributions (distributions), net	-	-	12,000
Investment in unconsolidated affiliates	-	295	(6,475)
Proceeds from sales of unconsolidated affiliates	6,654	-	-
Loans to affiliate	-	-	(490)
Proceeds from escrow deposit	1,380	-	-
(Increase) decrease in other long-term assets	82	444	(120)
Net cash provided by (used in) investing activities	197,838	(47,367)	(982,616)
Cash flows from financing activities:			
Proceeds from borrowings	139,630	100,000	375,463
Repayment of borrowings	(248,216)	(281,017)	(135,753)
Installments paid on property acquisition	(100,000)	(100,000)	-
Payment of deferred financing costs	(3,232)	(2,842)	(7,590)
Proceeds from sale of offshore litigation contingent payment rights	-	25,000	-
Repurchase of offshore litigation contingent payment rights	-	(25,000)	-
Stock issued for cash, net	-	246,905	662,043
Stock issued for cash upon exercise of options	-	-	4,827
Stock repurchased for withholding taxes	(747)	(380)	(1,368)
Proceeds from issuance of convertible debt	-	-	-
Net cash provided by (used in) financing activities	(212,565)	(37,334)	897,622
Net increase (decrease) in cash and cash equivalents	(46,265)	(3,557)	55,682
Cash at beginning of year	61,918	65,475	9,793
Cash at end of year	$ 15,653	$ 61,918	$ 65,475
Supplemental cash flow information:			
Cash paid for interest and financing costs	$ 27,639	$ 39,953	$ 29,894

See accompanying notes to consolidated financial statements.

(1) Nature of Organization

Delta Petroleum Corporation ("Delta" or the "Company") is principally engaged in acquiring, exploring, developing and producing oil and gas properties. The Company's core area of operations is the Rocky Mountain Region in which the majority of its proved reserves, production and long-term growth prospects are concentrated.

The Company owns a 49.8% interest in DHS Drilling Company ("DHS"), an affiliated Colorado corporation that is headquartered in Casper, Wyoming. Delta representatives currently constitute a majority of the members of the Board of DHS and Delta has the right to use all of the rigs owned by DHS on a priority basis and, accordingly, DHS is consolidated in these financial statements. During the second quarter of 2006, DHS engaged in a reorganization transaction pursuant to which it became a subsidiary of DHS Holding Company, a Delaware corporation, and the Company's ownership interest became an interest in DHS Holding Company. References to DHS include both DHS Holding Company and DHS, unless the context otherwise requires. DHS is a consolidated subsidiary of Delta.

At December 31, 2010, the Company owned 4,277,977 shares of the common stock of Amber Resources Company of Colorado ("Amber"), representing 91.68% of the outstanding common stock of Amber. Amber is a public company that owned undeveloped oil and gas properties in federal units offshore California, near Santa Barbara prior to the resolution of litigation with the United States government (see Note 4, "Oil and Gas Properties"). In conjunction with the settlement of such litigation, the leases owned by Amber were conveyed to the United States. As a result, Amber's only remaining asset is cash on hand and there are no ongoing operations. It is currently anticipated that Amber will remain in existence until the outcome of litigation involving one of the offshore California leases that was assigned back to the U.S. government is resolved (See Note 15, "Commitments and Contingencies").

(2) Going Concern

The accompanying financial statements have been prepared assuming the Company will continue as a going concern.

On July 23, 2010, the Company entered into a definitive Purchase and Sale Agreement with Wapiti Oil & Gas, L.L.C. ("Wapiti") to sell all or a portion of its interests in various non-core assets primarily located in Colorado, Texas and Wyoming (the "Wapiti Transaction") for cash proceeds of $130.0 million. The Wapiti Transaction closed on July 30, 2010 and all amounts escrowed at the original closing pending third party consents or rights of first refusal were subsequently received.

On December 29, 2010, the Company entered into the Third Amended and Restated Credit Agreement (the "MBL Credit Agreement"), with Macquarie Bank Limited ("MBL"), as administrative agent and issuing lender as more fully described in Note 7, "Long-Term Debt." The MBL Credit Agreement provides for a revolving loan (and a term loan each with a maturity date of January 31, 2012. The revolving loan has an initial borrowing base of $30.0 million and the term loan had an initial commitment of $20.0 million subject to a development plan that must be approved by MBL. The MBL Credit Agreement was amended on March 14, 2011 to provide for additional availability under the term loan, among other changes more fully described in Note 20, "Subsequent Events."

Proceeds from the Wapiti Transaction and the MBL Credit Agreement were used to substantially reduce amounts outstanding under the Company's prior credit facility, as well as to extend the maturity of the remaining balance that would have otherwise been due from January 15, 2011 to January 31, 2012, and to fund capital expenditures. Despite these improvements to the financial position of the Company, during 2010 the Company experienced a net loss attributable to Delta common stockholders of $182.3 million for the year ended December 31, 2010, and at December 31, 2010 had a working capital deficiency of $72.0 million, including $69.6 million outstanding under the credit agreement of DHS, the Company's 49.8% subsidiary (which is classified as current liabilities in the accompanying balance sheet). In addition, the amounts outstanding under the Company's credit facility are due on January 31, 2012 and the holders of the Company's $115.0 million $3^3/_4$% senior convertible notes have the option to require the Company to repurchase the notes at par on May 1, 2012.

(2) Going Concern, Continued

At December 31, 2010, DHS was in not in compliance with its financial covenants and on January 1, 2011, DHS did not pay its scheduled principal and interest payment. As a result, DHS entered into a forbearance agreement that currently expires on March 25, 2011. Although DHS is in ongoing negotiations with its lender, Lehman Commercial Paper, Inc. ("LCPI") to modify the terms of the existing DHS credit facility, there can be no assurance that DHS will be able to renegotiate the terms of its debt agreement or obtain an extension to the forbearance agreement that expires on March 25, 2011. If DHS is unable to extend the forbearance agreement or modify the terms of its debt agreement, and if LCPI exercises its default rights upon expiration of the forbearance period, including demanding immediate payment of all amounts outstanding under the debt agreement, DHS is not anticipated to have sufficient capital to repay the amounts due. The DHS facility is non-recourse to Delta. Subsequent to year-end, the Board of Directors of DHS engaged transaction advisors to commence a strategic alternatives process, focused on a sale of the company or substantially all of its assets. There can be no assurance that the terms offered by a potential buyer, if any, will be acceptable to the DHS shareholders. Additionally, the consummation of certain transactions are subject to the approval of DHS's senior lender and the proceeds received will be required to be used to pay down amounts outstanding under its DHS credit facility.

While the Wapiti Transaction and the MBL Credit Agreement significantly improved the Company's financial position, the Company does not have the capital on hand necessary to repay its credit facility borrowings due on January 31, 2012 or fund the purchase of convertible notes that may be put to the Company on May 1, 2012.

The Company believes that the amounts available under the Company's credit facility, as recently amended, combined with projected net cash from operating activities, will provide sufficient liquidity to fund our operating expenses, the limited Vega Area capital development planned, and maintain current debt service obligations. To the extent cash flows from operating activities are not sufficient to support future capital expenditures beyond those currently planned, and in order to address the January 2012 maturity of the Company's credit facility and the potential mandatory redemption in May 2012 of the $115.0 million senior convertible notes, it is likely that the Company will need to seek additional sources of long-term capital (including the issuance of equity, debt instruments, sales of assets and joint venture financing), as well as consider other potential corporate transactions such as a sale of the company. The timing, term, size, and pricing of any such financing or transaction will depend on investor interest and market conditions, as well as the Company's drilling and completion results, and there can be no assurance that the Company will be able to obtain any such financing or consummate any such transaction, and if so, that it will be on terms satisfactory to the Company which raises substantial doubt about the Company's ability to continue as a going concern. The financial statements do not include any adjustments that might result from the outcome of uncertainty regarding the Company's ability to raise additional capital, sell assets, or otherwise obtain sufficient funds to meet its obligations.

(3) Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of Delta and its consolidated subsidiaries (collectively, the "Company"). All inter-company balances and transactions have been eliminated in consolidation. Certain of the Company's oil and gas activities are conducted through partnerships and joint ventures, including CRB Partners, LLC ("CRBP") and through the date of the Wapiti Transaction, PGR Partners, LLC ("PGR"). The Company includes its proportionate share of assets, liabilities, revenues and expenses from these entities in its consolidated financial statements. The Company does not have any off-balance sheet financing arrangements (other than operating leases) or any unconsolidated special purpose entities.

(3) Summary of Significant Accounting Policies, Continued

Investments in operating entities where the Company has the ability to exert significant influence, but does not control the operating and financial policies, are accounted for using the equity method. The Company's share of net income of these entities is recorded as income (losses) from unconsolidated affiliates in the consolidated statements of operations. Investments in operating entities where the Company does not exert significant influence are accounted for using the cost method, and income is only recognized when a distribution is received.

Investments in operating entities where the Company has the ability to exert significant influence, but does not control the operating and financial policies, are accounted for using the equity method. The Company's share of net income of these entities is recorded as income (losses) from unconsolidated affiliates in the consolidated statements of operations. Investments in operating entities where the Company does not exert significant influence are accounted for using the cost method, and income is only recognized when a distribution is received.

Certain reclassifications have been made to amounts reported in the previous periods to conform to the current presentation. Among other items, revenues and expenses on certain properties that were sold during the year ended December 31, 2010 have been reclassified from continuing operations to discontinued operations for all periods presented. Such reclassifications had no effect on net loss (see Note 4, "Oil and Gas Properties – Discontinued Operations").

Cash Equivalents

Cash equivalents consist of money market funds and certificates of deposit. The Company considers all highly liquid investments with maturities at date of acquisition of three months or less to be cash equivalents.

Marketable Securities

During 2008, the Company determined that available for sale securities held by the Company had incurred an other than temporary loss and an impairment charge of $4.6 million was recorded in other expense during the year ended December 31, 2008. During late 2009, the securities were sold for proceeds of $2.0 million and the Company recorded a gain of $52,000. During 2010, all remaining marketable securities were sold for proceeds of $300,000 resulting in a gain of $300,000, as the carrying value had been fully impaired in 2008.

Inventories

Inventories consist of pipe and other production equipment not yet in use. Inventories are stated at the lower of cost (principally first-in, first-out) or estimated net realizable value. During 2008, the Company pre-ordered and stockpiled significant amounts of tubing, casing and pipe inventory to ensure availability for its then aggressive Piceance Basin and Paradox Basin drilling programs. Subsequently, with significantly lower commodity prices resulting in significant reductions in drilling capital expenditures and delays to drilling plans and with continued declines in steel prices, particularly during the second quarter of 2009, the value of these inventories had declined. As a result, during the three months ended June 30, 2009, the Company recorded an impairment of $4.3 million to the carrying value of its inventories, which is reflected in the accompanying consolidated statement of operations for the year ended December 31, 2009 as a component of dry hole costs and impairments.

Non-Controlling Interest

Non-controlling interest represents the 50.2% (47.2% for Chesapeake Energy Corporation and 3% for DHS executive officers and management) investors of DHS at December 31, 2010, 2009 and 2008, respectively.

(3) Summary of Significant Accounting Policies, Continued

Revenue Recognition

Oil and Gas

Revenues are recognized when title to the products transfers to the purchaser. The Company follows the "sales method" of accounting for its natural gas and crude oil revenue, so that the Company recognizes sales revenue on all natural gas or crude oil sold to its purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. A liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. As of the years ended December 31, 2010 and 2009, the Company's aggregate natural gas and crude oil imbalances were not material to its consolidated financial statements.

Drilling and Trucking

The Company earns its contract drilling revenues under daywork or turnkey contracts. The Company recognizes revenues on daywork contracts for the days completed based on the dayrate specified in the contract. Turnkey contracts are accounted for on a percentage-of-completion basis. The costs of drilling the Company's own oil and gas properties are capitalized in oil and gas properties as the expenditures are incurred. Trucking and hauling revenues are recognized based on either an hourly rate or a fixed fee per mile depending on the type of vehicle, the services performed, and the contract terms.

Property and Equipment

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under such method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological or geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but evaluated quarterly and charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the units-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties with significant acquisition costs are assessed quarterly on a property-by-property basis and any impairment in value is charged to expense. If the unproved properties are determined to be productive, the related costs are transferred to proved gas and oil properties. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain or loss until all costs have been recovered.

Depreciation and depletion of capitalized acquisition, exploration and development costs are computed on the units-of-production method by individual fields as the related proved reserves are produced.

Drilling equipment is recorded at cost or estimated fair value upon acquisition and depreciated on a component basis using the straight-line method over its estimated useful life ranging from five to 15 years. Pipelines and gathering systems and other property and equipment are recorded at cost and depreciated using the straight-line method over their estimated useful lives ranging from three to 40 years.

Depreciation, depletion, amortization and accretion of oil and gas property and equipment for the years ended December 31, 2010, 2009 and 2008 were $58.3 million, $81.3 million, and $80.2 million, respectively.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable.

(3) Summary of Significant Accounting Policies, Continued

Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions and projections. For proved properties, if the expected future cash flows exceed the carrying value of the asset, no impairment is recognized. If the carrying value of the asset exceeds the expected future cash flows, an impairment exists and is measured by the excess of the carrying value over the estimated fair value of the asset. Any impairment provisions recognized are permanent and may not be restored in the future.

The Company assesses proved properties on an individual field basis for impairment on at least an annual basis. During the year ended December 31, 2010, the Company recorded an impairment provision related to continuing operations attributable to proved properties of $1.1 million for the year ended December 31, 2010, which are included within dry hole costs and impairments in the accompanying statement of operations.

During the year ended December 31, 2009, the Company recorded impairments related to continuing operations attributable to proved properties totaling approximately $24.3 million primarily related to the Angleton, Laurel Ridge, and Opossum Hollow fields in Texas of $20.9 million and other miscellaneous fields of $3.4 million. The impairments resulted primarily from the significant decline in commodity pricing for most of 2009 causing downward revisions to proved reserves which led to impairments.

During the year ended December 31, 2008, the Company recorded impairments related to continuing operations attributable to proved properties totaling approximately $208.1 million primarily related to the Newton, Midway Loop, and Opossum Hollow fields in Texas of $172.1 million, the Paradox field in Utah of $26.2 million and the Company's offshore California field of $9.8 million. The impairments resulted primarily from the significant decline in commodity pricing during the fourth quarter of 2008. In addition, the Company recorded an impairment to the Paradox pipeline of $21.5 million in 2008.

For unproved properties, the need for an impairment is based on the Company's plans for future development and other activities impacting the life of the property and the ability of the Company to recover its investment. When the Company believes the costs of the unproved property are no longer recoverable, an impairment charge is recorded based on the estimated fair value of the property.

As a result of such assessment, the Company recorded impairment provisions attributable to unproved properties of $42.4 million for the year ended December 31, 2010 which primarily included $13.2 million related to the Company's Columbia River Basin leasehold, $6.2 million related to the Company's Hingeline leasehold, $3.8 million related to the Company's Haynesville leasehold, $4.0 million related to the Company's Delores River leasehold, $1.6 million related to the Company's non-operated Garden Gulch leasehold, and $661,000 related to the Company's Howard Ranch leasehold. The Company also recorded impairments of $6.7 million related to the produced water handling facility in Vega, and $4.9 million to reduce the Paradox pipeline carrying value to its estimated fair value. These impairment provisions are included within dry hole costs and impairments in the accompanying statements of operations for the year ended December 31, 2010. These impairments generally resulted from the lack of success in marketing these non-core assets combined with our lack of plans to develop the acreage.

As a result of such assessment, the Company recorded impairment provisions attributable to unproved properties of $123.5 million for the year ended December 31, 2009, including $38.6 million related to the Company's non-operated Piceance leasehold in Garden Gulch, $27.5 million related to leasehold in the Haynesville Shale, $21.4 million related to the Company's Columbia River Basin leasehold due to a dry hole drilled on this acreage, $14.8 million related to leasehold in Lighthouse Bayou, $8.3 million primarily associated with the Company's development plans for certain Gulf Coast properties and near-term expiring leases not expected to be renewed, and $2.4 million related to expired and expiring acreage in the Newton field. In addition, the Company recorded an impairment of $10.5 million to reduce the Company's Vega area surface land carrying value to its estimated fair value. These impairments are included within dry hole costs and impairments in the accompanying statement of operations for the year ended December 31, 2009. These impairments generally resulted from sustained lower commodity prices for most of 2009, near term expiring leasehold, unsuccessful drilling results, or our inability to meet contractual drilling obligations.

(3) Summary of Significant Accounting Policies, Continued

During the year ended December 31, 2008, the Company recorded impairments of its unproved properties totaling $66.4 million, primarily related to Utah Hingeline of $40.2 million, Opossum Hollow, Newton and Angleton in Texas of $19.2 million, certain prospects in Colorado of $4.0 million, and the Paradox basin in Utah of $3.0 million.

For 2011, the Company plans to develop and evaluate certain proved and unproved properties. Favorable or unfavorable drilling results or changes in commodity prices may cause a revision to estimates of those properties' future cash flows. Such revisions of estimates could require the Company to record additional impairments in the period of such revisions.

Goodwill

Goodwill represented the excess of the cost of the acquisitions by DHS of C&L Drilling in May 2006, Rooster Drilling in March 2006, and Chapman Trucking in November 2005 over the fair value of the assets and liabilities acquired. For goodwill and intangible assets recorded in the financial statements, an impairment test is performed at least annually in accordance with applicable FASB guidance. Although no impairment of goodwill was indicated as a result of the Company's annual impairment test performed during the third quarter of 2008, an impairment for the full amount of goodwill ($7.7 million) was recorded during the fourth quarter of 2008 as a result of impairment testing prompted by the decline in commodity prices resulting in the deteriorating utilization rate of the Company's rig fleet in the fourth quarter.

Asset Retirement Obligations

The Company's asset retirement obligations arise from the plugging and abandonment liabilities for its oil and gas wells. The Company has no obligation to provide for the retirement of most of its offshore properties as the obligations remained with the seller from whom the Company acquired the properties. The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Asset retirement obligation – beginning of period	$ 10,539	$ 8,737	$ 5,199
Accretion expense	445	517	436
Change in estimate	(252)	465	1,883
Obligations incurred (from new wells)	382	1,908	2,579
Obligation assumed	-	375	-
Obligations settled	(1,532)	(564)	(1,065)
Obligations on sold properties	(4,436)	(899)	(295)
Asset retirement obligation – end of period	5,146	10,539	8,737
Less: Current asset retirement obligation	(1,217)	(2,885)	(2,152)
Long-term asset retirement obligation	$ 3,929	$ 7,654	$ 6,585

Comprehensive Income (Loss)

Comprehensive income (loss) includes all changes in equity during a period except those resulting from investments by owners and distributions to owners, if any. For the years ended December 31, 2010, 2009, and 2008 comprehensive loss was $194.0 million, $349.7 million, and $467.6 million, respectively.

Financial Instruments

The Company periodically enters into commodity price risk transactions to manage its exposure to oil and gas price volatility. These transactions may take the form of futures contracts, collar agreements, swaps or options. The purpose of the transactions is to provide a measure of stability to the Company's cash flows in an environment of volatile oil and gas prices. The Company has not elected hedge accounting and recognizes mark-to-market gains and losses in earnings currently. See Note 10, "Commodity Derivative Instruments" for additional information.

(3) Summary of Significant Accounting Policies, Continued

Executive Severance Agreements

On May 26, 2009, the Company's then Chairman of the Board of Directors and Chief Executive Officer, Roger A. Parker, resigned from the Company. In conjunction with Mr. Parker's resignation, Delta entered into a severance agreement, effective as of the close of business on May 26, 2009, whereby Mr. Parker resigned from his positions as Chairman of the Board, Chief Executive Officer and as a director of Delta, as well as his positions as a director, officer and employee of Delta's subsidiaries. In consideration for Mr. Parker's resignation and his agreement to (a) relinquish all his rights under his employment agreement, his change-in-control agreement, certain stock agreements, bonuses relating to past and pending transactions benefiting Delta, and any other interests he might claim arising from his efforts as Chairman of the Company's Board of Directors and/or Chief Executive Officer, and (b) stay on as a consultant to facilitate an orderly transition and to assist in certain pending transactions, the Company agreed to pay Mr. Parker $4.7 million in cash (the "Cash Consideration"), issue to him 1.0 million shares of Delta common stock (the "Shares"), pay him the aggregate of any accrued unpaid salary, vacation days and reimbursement of his reasonable business expenses incurred through the effective date of the agreement, and provide to him insurance benefits similar to his pre-resignation benefits for a thirty-six month period. The Severance Agreement also contains mutual releases and non-disparagement provisions, as well as other customary terms.

The table below summarizes the total executive severance expense included in the accompanying statements of operations for the year ended December 31, 2009 (in thousands):

Cash consideration – immediately available funds	$	1,812
Cash consideration – rabbi trust		2,888
Stock consideration – rabbi trust		1,700
Subtotal		6,400
Performance shares forfeited		(2,293)
Retention stock forfeited		(525)
Health, medical and other benefits payable		75
Legal costs and other expenses		82
Total executive severance expense	$	3,739

In accordance with the terms of the severance agreement, Mr. Parker received a portion of the cash consideration in immediately available funds, and the remaining cash consideration and the shares were deposited in a rabbi trust which was then distributed to Mr. Parker on or about November 27, 2009. The assets of the rabbi trust were required to be consolidated into the financial statements of the Company as such assets were subject to the claims of the Company's creditors under federal and state law. Stock consideration deposited into the rabbi trust was reflected as treasury stock valued at the market value of the common shares on the date of issuance in the accompanying consolidated balance sheet of the Company, with an offsetting amount recorded as executive severance payable in common stock included as a component of stockholders' equity.

On July 6, 2010, John Wallace, the then President, Chief Operating Officer and a Director of the Company, resigned from all of his positions as director, officer and employee of the Company and any of its subsidiaries. In conjunction with such resignation, the Company entered into a severance agreement with Mr. Wallace pursuant to which he agreed to (a) relinquish certain rights under his employment agreement, his change-in-control agreement, certain stock agreements, bonuses relating to past and pending transactions benefiting Delta, and certain other interests he might claim arising from his efforts in his previous capacities with the Company and its subsidiaries, and (b) make himself reasonably available to answer questions to facilitate an orderly transition. Under the terms of his severance arrangement, the Company paid Mr. Wallace a lump sum of $1.6 million, paid him his salary for the full month in which his resignation occurred and for his accrued vacation days, reimbursed him for his reasonable business

(3) Summary of Significant Accounting Policies, Continued

expenses incurred through the effective date of the agreement, and agreed to provide to him insurance benefits similar to his pre-resignation benefits for the period in which Mr. Wallace is entitled to receive COBRA coverage under applicable law. The severance agreement also contained mutual releases and non-disparagement provisions, as well as other customary terms.

The table below summarizes the total executive severance expense included in the accompanying statements of operations for the year ended December 31, 2010 (in thousands):

Cash consideration – immediately available funds	$	1,600
Performance shares forfeited		(2,274)
Total executive severance expense (benefit)	$	(674)

Equity compensation costs previously recorded in the consolidated financial statements related to performance shares forfeited prior to their derived service period and retention stock forfeited prior to vesting as a result of the severance agreements for Mr. Parker and Mr. Wallace were reversed and reflected as a reduction of executive severance expense.

Stock Based Compensation

The Company recognizes the cost of share based payments over the period the employee provides service and includes such costs in general and administrative expense in the statements of operations.

Income (Loss) from Unconsolidated Affiliates

Income (loss) from unconsolidated affiliates includes the Company's share of earnings or losses from equity method investments. In addition, during 2009, the Company recognized impairments to the carrying value of its investment in Delta Oilfield Tank Company ("DOTC") of $3.3 million to reduce the carrying value of the Company's investment in DOTC to zero. The impairments were precipitated by DOTC's increasing losses during 2009 compared to prior periods and deterioration of its operating results compared to its budgeted results. During 2009, the Company engaged third party investment advisers to assist in evaluating strategic alternatives relating to the Company's investment in DOTC. Subsequently, a planned transaction did not occur and the remaining equity carrying value was reduced to zero. As a result of these events, the Company also recorded a bad debt reserve of $5.0 million to reduce the carrying value of the Company's note receivable from DOTC to the amount estimated to be collectible.

At December 31, 2009, the Company owned a 5% interest in Collbran Valley Gas Gathering, LLC ("CVGG") which operates a pipeline in the Piceance Basin through which the Company transports its produced gas to the sales point. In early 2010, the Company divested of this interest for cash proceeds of $3.5 million, plus an additional $2.0 million of proceeds contingent on volume deliveries through the CVGG system of Delta gas between January 1, 2010 and June 30, 2011. Based on current production levels, the Company is not likely to earn the contingent consideration without the initiation of a continuous drilling program which could only be undertaken with additional funding beyond the Company's existing capital resources. As a result of this transaction, the Company recorded an impairment during the year ended December 31, 2009 of its investment in CVGG of $1.4 million to reduce the carrying value to its fair value.

In addition, during the quarter ended December 31, 2009, the Company recognized an impairment of the carrying value of its investment in Ally Equipment Company, LLC ("Ally") of $3.4 million, which reduced the carrying value of the Company's investment in Ally to approximately $1.0 million. The impairment was precipitated by Ally's increasing losses during the year ended 2009 compared to prior periods and the outlook for 2010.

(3) Summary of Significant Accounting Policies, Continued

The Company also recorded an impairment of $917,000 to write-off its carrying value in the entity that was expected to operate the Paradox pipeline as other plans related to the future of the entity did not materialize during the second quarter of 2009. These impairments are included within income (loss) from unconsolidated affiliates in the accompanying statement of operations for the year ended December 31, 2009.

In September 2010, the Company sold its 50% interest in Ally for $1.5 million, including $250,000 received during the third quarter, $250,000 received in January 2011 and four remaining $250,000 quarterly installments to be paid each quarter end commencing on March 31, 2011. The Company recognized a loss of $522,000 on the transaction which is included as a component of income (loss) from unconsolidated affiliates for the year ended December 31, 2010.

In December 2010, the Company sold its 50% interest in DOTC for $4.9 million, including $2.8 million received in 2010, with the remaining $2.1 million due in equal monthly installments of $29,500 for 72 months commencing in February 2011. The Company recognized a gain of $676,000 on the transaction which is included as a component of income (loss) from unconsolidated affiliates for the year ended December 31, 2010.

Non-Qualified Stock Options - Directors and Employees

On December 22, 2009, the stockholders approved the Company's 2009 Performance and Equity Plan (the "2009 Plan"). Subject to adjustment as provided in the 2009 Plan, the number of shares of Common Stock that may be issued or transferred, plus the amount of shares of Common Stock covered by outstanding awards granted under the 2009 Plan, may not in the aggregate exceed 30 million. The 2009 Plan supplements the Company's 1993, 2001, 2004 and 2007 Incentive Plans. The purpose of the 2009 Plan is to provide incentives to selected employees and directors of the Company and its subsidiaries, and selected non-employee consultants and advisors to the Company and its subsidiaries, who contribute and are expected to contribute to the Company's success.

Incentive awards under the 2009 Plan may include non-qualified or incentive stock options, limited appreciation rights, tandem stock appreciation rights, phantom stock, stock bonuses or cash bonuses. Options issued to date under the Company's various incentive plans have been non-qualified stock options as defined in such plans.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and net operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted income tax rates expected to apply to taxable income in the years in which those differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in income tax rates is recognized in the results of operations in the period that includes the enactment date. The realizability of deferred tax assets is evaluated based on a "more likely than not" standard, and to the extent this threshold is not met, a valuation allowance is recorded. The Company is currently providing a full valuation allowance on its net deferred tax assets, including the net deferred tax assets of DHS.

Income (Loss) per Common Share

Basic income (loss) per share is computed by dividing net income (loss) attributed to common stock by the weighted average number of common shares outstanding during each period, excluding treasury shares. Diluted income (loss) per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of convertible preferred stock, convertible debt, stock options, restricted stock and warrants. (See Note 13, "Earnings Per Share").

(3) Summary of Significant Accounting Policies, Continued

Major Customers

During the year ended December 31, 2010, customer A and customer B accounted individually for 45% and 18%, respectively, of the Company's total oil and gas sales. During the year ended December 31, 2009, customer A and customer B accounted individually for 37% and 19%, respectively, of the Company's total oil and gas sales. During the year ended December 31, 2008, customer A and customer C individually accounted for 31% and 25%, respectively, of the Company's total oil and gas sales. In addition, during the year ended December 31, 2010, Customer E individually accounted for 37% of DHS's contract drilling and trucking fees.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include oil and gas reserves, bad debts, depletion and impairment of oil and gas properties, valuations of marketable securities, income taxes, derivatives, asset retirement obligations, contingencies and litigation accruals. Actual results could differ from these estimates.

(4) Oil and Gas Properties

Unproved Undeveloped Offshore California Properties

The Company previously owned direct and indirect ownership interests ranging from 2.49% to 100% in five unproved undeveloped offshore California oil and gas properties. The Company and its 92% owned subsidiary, Amber, were among twelve plaintiffs in a lawsuit that was filed in the United States Court of Federal Claims (the "Court") in Washington, D.C. alleging that the U.S. government materially breached the terms of forty undeveloped federal leases, some of which are part of the Company's offshore California properties. During 2009, the Company received net proceeds of $95.8 million after overrides and conveyed its leases back to the United States. Accordingly, the Company no longer has any remaining unproved undeveloped offshore California property interests.

Year Ended December 31, 2010 – Divestitures

During the year ended December 31, 2010, the Company divested of its interests in certain non-core properties for gross proceeds of $980,000 and the assumption of plugging and abandonment obligations. Proved reserves attributable to these properties were insignificant.

On July 23, 2010, we entered into a definitive Purchase and Sale Agreement with Wapiti to sell all or a portion of our interest in various non-core assets primarily located in Colorado, Texas, and Wyoming for gross cash proceeds of $130.0 million resulting in a net loss of $66.5 million (including impairment losses of $96.2 million). For financial reporting purposes, a $4.0 million impairment loss is included within dry hole costs and impairments in continuing operations, $92.2 million of impairments are included within loss from discontinued operations, and a $29.7 million gain on sale is included in gain on sale of discontinued operations.

(4) Oil and Gas Properties, Continued

Year Ended December 31, 2009 – Divestitures

During the fourth quarter of 2009, in a series of transactions the Company divested certain non-operated properties in North Dakota, Alabama, California, Colorado, Louisiana, North Dakota, Oklahoma, Texas, and Wyoming. Proceeds were $4.7 million and a loss of $2.1 million was recorded as a component of gain on offshore litigation and property sales, net, in the accompanying consolidated statement of operations. Minimal production and reserves were attributable to the properties.

Year Ended December 31, 2008 – Acquisitions/Divestitures

On September 15, 2008, the Company entered into an agreement with EnCana Oil & Gas (USA), Inc. ("EnCana") to acquire all of EnCana's net leasehold position and interest in wells in the Columbia River Basin of Washington and Oregon. The purchase price for the leasehold properties was $25.0 million and the transaction closed on September 26, 2008. On September 26, 2008, the Company completed a separate transaction related to the Columbia River Basin wherein the Company sold a 50% working interest participation in all of the Company's Columbia River Basin leaseholds and wells for cash consideration of $42.0 million plus one half of the drilling costs incurred to date on the Company's well currently drilling in the area. This transaction included a 50% working interest in the leaseholds acquired from EnCana on September 15, 2008.

On August 25, 2008, the Company completed an asset exchange agreement in which the Company acquired additional incremental interests in certain Midway Loop properties in exchange for $15.1 million in cash and non-core undeveloped properties in Divide Creek. The transaction resulted in a gain of $715,000 on the exchange during the three months ended September 30, 2008.

In July and August 2008, the Company completed several transactions to acquire unproved leasehold interests in two prospect areas. The total cost of the acquisitions was approximately $41.6 million. Pursuant to one of the agreements, the Company is obligated to spud an initial appraisal well by July 1, 2009.

On February 28, 2008, the Company closed a transaction with EnCana to jointly develop a portion of EnCana's leasehold in the Vega Area of the Piceance Basin. Delta acquired over 1,700 drilling locations on approximately 18,250 gross acres with a 95% working interest. The effective date of the transaction was March 1, 2008.

Discontinued Operations

In accordance with accounting standards, the results of operations and impairment loss relating to certain of the Wapiti Transaction properties have been reflected as discontinued operations. Properties associated with the Wapiti Transaction in which the Company only sold half of its interest continue to be reported as a component of continuing operations. The fields classified as discontinued operations are fields in which the Company sold all of its interest including the Garden Gulch field, Baffin Bay field, and Bull Canyon field as well as the Company's interest in its wholly-owned subsidiary Piper Petroleum. In separate transactions, the Company sold its interest in the Howard Ranch field and the Laurel Ridge field and has included this property as discontinued operations as well.

(4) Oil and Gas Properties, Continued

The following table shows the total oil and gas segment revenues and expenses included in discontinued operations for the above mentioned oil and gas properties for the years ended December 31, 2010, 2009 and 2008 (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Revenues	$ 9,724	$ 12,239	$ 28,918
Operating expenses:			
Lease operating expense	2,781	4,864	5,612
Transportation expense	1,461	1,555	3,470
Production taxes	612	820	890
Depreciation, depletion, amortization and accretion	13,842	27,170	18,907
Impairments	92,162	12,201	27,860
Total operating expenses	110,858	46,610	56,739
Loss from discontinued operations	(101,134)	(34,371)	(27,821)
Income tax expense	-	-	-
Loss from results of operations of discontinued properties, net of tax	(101,134)	(34,371)	(27,821)
Gain on sales of discontinued operations	28,978	-	718
Total loss from discontinued operations	$ (72,156)	$ (34,371)	$ (27,103)

On July 30, 2010, the Company closed on the Wapiti Transaction for cash proceeds of $130.0 million, with approximately $108.5 million used to reduce amounts outstanding under the credit facility, $3.7 million used to pay transaction related costs, and $17.8 million initially paid into escrow pending the receipt of third party consents required to transfer ownership of certain properties involved in the Wapiti Transaction. The escrowed proceeds were received in October 2010. As a result of the Wapiti Transaction, the Company recorded a net loss of $66.5 million (including impairment losses of $96.2 million). For financial reporting purposes, $4.0 million of the impairment loss is included within dry hole costs and impairments in continuing operations, $92.2 million of impairments are included within loss from discontinued operations, and a $29.7 million gain on sale is included in gain on sale of discontinued operations.

On August 27, 2010, the Company closed on the Howard Ranch sale for cash proceeds of $550,000. The Company recognized a loss on sale of $687,000. During 2009, the Company recorded impairments on the Howard Ranch and Laurel Ridge fields of $1.5 million and $10.7 million, respectively, as a result of the significant decline in commodity pricing for most of 2009 causing downward revisions to proved reserves which led to impairments.

For the year ended December 31, 2008, gain on sale of discontinued operations includes a minor adjustment of $718,000 to the gain on the asset exchange of non-core undeveloped properties in Divide Creek along with $15.1 million in cash for additional incremental interests in certain Midway Loop properties. During 2008, the Company recorded impairments on the Howard Ranch and Bull Canyon fields of $21.8 million and $6.1 million, respectively.

(5) DHS Drilling Company

On December 31, 2010 and 2009, the Company owned a 49.8% ownership interest in DHS. The remaining interest is owned by Chesapeake Energy Corporation, 47.2%, and 3% by DHS executive officers and management.

During 2008, DHS acquired three rigs and spare equipment for a purchase price of $23.3 million. The transaction was funded by the proceeds from two notes payable issued to Delta and Chesapeake of $6.0 million each and from proceeds of $6.0 million each from Delta and Chesapeake for additional shares of common stock issued by DHS. The notes issued to both Delta and Chesapeake were later converted to DHS common shares.

Also during 2008, DHS acquired a 2,000 horsepower drilling rig with a 25,000 foot depth rating for a purchase price of $12.3 million (Rig #23). The acquisition was financed by an increase in the DHS credit facility.

Because of the bankruptcy of Lehman Commercial Paper and the inability of Lehman to fund DHS's credit facility during 2008, DHS was unable to close on an acquisition for which it had paid a $1.3 million deposit. DHS forfeited its deposit and accordingly, other expense for the year ended December 31, 2008 includes a $1.3 million loss on the forfeiture of the deposit.

As a result of the annual DHS goodwill impairment test and evaluation of rig values, DHS determined in 2008 that the book value of its rigs was impaired by $21.6 million and that goodwill of $7.7 million should be fully impaired. These impairments are included within goodwill and rig impairments in the accompanying statement of operations for the year ended December 31, 2008.

During 2009, DHS sold Rig #7 to Naknek Electric Association for cash proceeds of $7.8 million with a resulting gain of $1.6 million. The proceeds were used to reduce debt outstanding under the DHS credit facility (See Note 7, "Long-Term Debt").

The carrying value of DHS's drilling rigs and related equipment is assessed for impairment whenever circumstances indicate an impairment may exist. During 2009, an impairment of $6.5 million was recorded to reduce the carrying value of three drilling rigs and other spare rig equipment to their respective fair values. This impairment is included within goodwill and rig impairments in the accompanying statement of operations for the year ended December 31, 2009.

In January 2010, DHS entered into a daywork drilling contract with Desarrollos y Perforaciones De Mexico ("DPM") to drill geothermal wells for the benefit of the Mexican national electric company ("CFE") in the state of Puebla. The rig was released in July after drilling two wells. A total of $3.7 million was invoiced to DPM for the project with $1.6 million being collected to date. The balance of $2.1 million has been reserved as a doubtful account due to concerns regarding collection. Legal action is being taken to collect the amount owed to DHS. The rig has undergone minor reconditioning and has since been placed in service. In addition, another DHS customer filed bankruptcy during 2010 and its balance of $104,000 has been reserved as a doubtful account as well. (See also Note 15, "Commitments and Contingencies").

(6) Fair Value Measurements

Effective January 1, 2008, the Company follows accounting guidance which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and requires additional disclosures about fair value measurements. As required, the Company applied the following fair value hierarchy:

Level 1 – Assets or liabilities for which the item is valued based on quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 – Assets or liabilities valued based on observable market data for similar instruments.

Level 3 – Assets or liabilities for which significant valuation assumptions are not readily observable in the market; instruments valued based on the best available data, some of which is internally-developed, and considers risk premiums that a market participant would require.

The level in the fair value hierarchy within which the fair value measurement in its entirety falls shall be determined based on the lowest level input that is significant to the fair value measurement in its entirety.

Derivative liabilities consist of future oil and gas commodity swap contracts valued using both quoted prices for identically traded contracts and observable market data for similar contracts (NYMEX WTI oil, NYMEX Henry Hub gas and CIG gas swaps – Level 2).

Proved property impairments - The fair values of the proved properties are estimated using internal discounted cash flow calculations based upon the Company's estimates of reserves and are considered to be level three fair value measurements.

Asset retirement obligations - The initial fair values of the asset retirement obligations are estimated using internal discounted cash flow calculations based upon the Company's asset retirement obligations, including revisions of the estimated fair values in 2010 and 2009.

The following table lists the Company's fair value measurements by hierarchy as of December 31, 2010 (in thousands):

Assets (Liabilities)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total December 31, 2010
Recurring				
Derivative liabilities	$ -	$ (2,993)	$ -	$ (2,993)

The following table lists the Company's fair value measurements by hierarchy as of December 31, 2009 (in thousands):

Assets (Liabilities)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total December 31, 2009
Recurring				
Derivative liabilities	$ -	$ (26,972)	$ -	$ (26,972)

(7) Long-Term Debt

On February 28, 2008, the Company closed a transaction with EnCana to jointly develop a portion of EnCana's leasehold interests in the Vega Area of the Piceance Basin. Under the terms of the agreement, the Company has committed to fund $410.1 million, of which $110.5 million was paid at the closing, $99.6 million was paid on November 1, 2009, $100.0 million was paid on October 28, 2010, and the remaining balance of $100.0 million is due November 1, 2011. The remaining installment is collateralized by a letter of credit, which in turn is collateralized by cash on deposit in a restricted account. The installment payment obligations were recorded in the accompanying consolidated financial statements as current and long-term liabilities at a discounted value, initially of $280.1 million, based on an imputed interest rate of 2.58%. The discount is being accreted on the effective interest method over the term of the installments, including accretion of $7.0 million and $4.6 million for the years ended December 31, 2009 and 2010, respectively.

7% Senior Unsecured Notes, due 2015

On March 15, 2005, the Company issued 7% senior unsecured notes for an aggregate amount of $150.0 million which pay interest semi-annually on April 1 and October 1 and mature in 2015 (the "Senior Notes"). The Senior Notes were issued at 99.50% of par and the associated discount is being amortized to interest expense over their term. The indenture governing the Senior Notes contains various restrictive covenants that may limit the Company's ability to, among other things, incur additional indebtedness, make certain investments, sell assets, consolidate, merge or transfer all or substantially all of its assets and the assets of its restricted subsidiaries. These covenants may limit management's discretion in operating the Company's business. In addition, in the event that a Change of Control should occur (as such term is defined in the indenture), each holder of the Senior Notes would have the right to require the Company to repurchase all or any part of such holder's notes at a purchase price in cash equal to 101% of the principal amount of the notes plus accrued and unpaid interest, if any, to the date of purchase.

3¾% Senior Convertible Notes, due 2037

On April 25, 2007, the Company issued $115.0 million aggregate principal amount of 3¾% Senior Convertible Notes due 2037 (the "Notes") for net proceeds of $111.6 million after underwriters' discounts and commissions of approximately $3.4 million. The Notes bear interest at a rate of 3¾% per annum, payable semi-annually in arrears, on May 1 and November 1 of each year, beginning November 1, 2007. The Notes will mature on May 1, 2037 unless earlier converted, redeemed or repurchased, but each holder of Notes has the option to require the Company to purchase any outstanding Notes on each of May 1, 2012, May 1, 2017, May 1, 2022, May 1, 2027 and May 1, 2032 at a price which is required to be paid in cash, equal to 100% of the principal amount of the Notes to be purchased. The Notes will be convertible at the holder's option, in whole or in part, at an initial conversion rate of 32.9598 shares of common stock per $1,000 principal amount of Notes (equivalent to a conversion price of approximately $30.34 per share) at any time prior to the close of business on the business day immediately preceding the final maturity date of the Notes, subject to prior repurchase of the Notes. The conversion rate may be adjusted from time to time in certain instances. Upon conversion of a Note, the Company will have the option to deliver shares of its common stock, cash or a combination of cash and shares of the Company's common stock for the Notes surrendered. In the event that a fundamental change occurs (as defined in the Indenture, but generally including a tender offer for a majority of the Company's securities, an acquisition by anyone of 50% or more of the Company's stock, a change in the majority of the Company's Board of Directors, the approval of a plan of liquidation or being delisted from a national securities exchange), each holder of Notes would have the right to require the Company to purchase all or a portion of its Notes for the price specified in the Indenture. In addition, following certain fundamental changes that occur prior to maturity, the Company will increase the conversion rate for a holder who elects to convert its Notes in connection with such fundamental changes by a number of additional shares of common stock. Also, the Company is not permitted to consolidate with or merge with or into, or convey, transfer, sell, lease or dispose of all or substantially all

(7) Long-Term Debt, Continued

of its assets unless the successor company meets certain requirements and assumes all of the Company's obligations under the Notes. If as a result of such transaction, the Notes become convertible into common stock or other securities issued by another issuer, the other issuer must fully and unconditionally guarantee all of the Company's obligations under the Notes. Although the Notes do not contain any financial covenants, the Notes contain covenants that require the Company to properly make payments of principal and interest, provide certain reports, certificates and notices to the trustee under various circumstances, cause its wholly-owned subsidiaries to become guarantors of the debt, maintain an office or agency where the Notes may be presented or surrendered for payment, continue the Company's corporate existence, pay taxes and other claims, and not seek protection from the debt under any applicable usury laws.

Credit Facility

On December 29, 2010, the Company entered into the Third Amended and Restated Credit Agreement (the "MBL Credit Agreement"), with Macquarie Bank Limited ("MBL"), as administrative agent and issuing lender. The MBL Credit Agreement provides for a revolving loan and a term loan each with a maturity date of January 31, 2012. The revolving loan has an initial borrowing base of $30.0 million and bears interest at prime plus 6% per annum for prime rate advances and LIBOR plus 7% per annum for LIBOR advances. The borrowing base for the revolving loan is subject to a semi-annual re-determination based on reserve reports as of each January 1 and July 1 as reported by the Company to MBL on or before each April 1 and October 1, respectively. At December 31, 2010, $29.1 million was outstanding under the revolving loan. The term loan had an initial commitment of $20.0 million subject to a development plan that must be approved by MBL. Advances under the term loan bear interest at prime plus 8% per annum for prime rate advances and LIBOR plus 9% for LIBOR advances. Borrowings under the term loan must be repaid on the 25th of each month following the first month that an advance under the term loan is outstanding in an amount equal to 100% of the Net Operating Cash Flow, as defined, calculated from the prior month. In addition, following the date on which the first advance under the term loan is made and continuing until all advances under the term loan have been paid in full, the Company will direct all purchaser payments and any other cash receipts to be deposited in a project account maintained at MBL. Funds will be released by MBL from the project account at the Company's request in order to pay revenues due to working interest and royalty interest owners and to pay operating costs, as defined, including lease operating expenses, production taxes, amounts due under hedging agreements, general and administrative expenses and interest payments. At December 31, 2010, no amounts had been borrowed under the term loan. The revolving loan and the term loan are subject to quarterly financial covenants, in each case as defined in the MBL Credit Agreement and described in summary here, including maintenance of a minimum current ratio of 1:1, minimum quarterly net operating cash flow of $8.6 million, and maximum quarterly general and administrative expenses (excluding equity based compensation) of $5.0 million. In addition, the Company may not permit its trade payables to be outstanding more than 90 days following the receipt of applicable invoices. At December 31, 2010, the Company was in compliance with its financial covenants under the MBL Credit Agreement. The MBL Credit Agreement was amended on March 14, 2011 to provide for additional availability under the term loan, among other changes more fully described in Note 20, "Subsequent Events."

Prior to the MBL Credit Agreement, on July 23, 2010, the Company entered into the Fourth Amendment to the Second Amended and Restated Credit Agreement, with JPMorgan Chase Bank, N.A., as agent, and certain of the financial institutions that were party to this credit agreement in which, among other changes, the requisite lenders consented to the Wapiti Transaction, subject to specified terms and conditions, including that the net proceeds from the transaction be used to pay down the balance outstanding under the credit facility and that the borrowing base be reduced to $35.0 million upon consummation of the Wapiti Transaction.

On April 26, 2010, the Company entered into the Third Amendment to the Second Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as agent, and certain of the financial institutions that were party to this credit agreement in which, among other changes, the borrowing base was reduced from $185.0 million with a $20.0

(7) Long-Term Debt, Continued

million required minimum availability to $145.0 million with no required minimum availability for a net reduction in the borrowing base of $20.0 million.

On October 30, 2009, the Company entered into the Second Amendment (the "Second Amendment") to the Second Amended and Restated Credit Agreement (as amended, the "Credit Agreement"), with JPMorgan Chase Bank, N.A., as agent, and certain of the financial institutions that are party to its credit agreement in which, among other changes, as part of a scheduled redetermination, the borrowing base was reduced from $225.0 million to $185.0 million with a minimum required availability of $20.0 million essentially further reducing the Company's availability under the Credit Agreement.

Borrowings under the MBL Credit Agreement were $29.1 million at December 31, 2010, with remaining availability of $7.1 million based on the $30.0 million revolver borrowing base and availability under the term loan.

Credit Facility – DHS

On April 1, 2010, DHS amended its existing credit facility with LCPI and renegotiated certain terms of the agreement including obtaining waivers for all covenant violations through March 31, 2010. The terms of the amended agreement required principal payments of approximately $7.7 million paid on April 1, 2010 and $2.0 million paid on each of May 1, 2010, August 1, 2010 and November 1, 2010, with a remaining $2.0 million principal payment due on January 1, 2011, and a $5.0 million principal payment due on each of April 1, 2011 and July 1, 2011 with the remaining balance of approximately $57.6 million due at maturity (August 31, 2011). In addition to the required payments, DHS may be required to prepay any remaining outstanding principal with the "Net Cash Proceeds from any Asset Sale," as defined by the credit facility, and any such prepayment shall be applied to, first, prepay the immediately succeeding Scheduled Installment in full, second, prepay all interest payable on the immediately succeeding Interest Payment Date in full, third, pay the second succeeding Scheduled Installment in full and fourth, prepay the remaining principal balance of the remaining loans. DHS is also required to prepay the principal amount of the loans in an amount equal to 75% of the "Excess Cash Flow," as defined by the credit facility, for such fiscal quarter. The financial covenants required in the DHS credit agreement include a minimum EBITDA covenant of $1.5 million for each quarter beginning December 31, 2010 and a capital expenditures limitation of $1.2 million for any fiscal quarter. Notwithstanding the $1.2 million per quarter limitation on capital expenditures, the amendment imposes aggregate capital expenditure limitations of $3.5 million for fiscal year 2010 and approximately $2.3 million for fiscal year 2011. The interest rate was adjusted to LIBOR plus 625 basis points, subject to a LIBOR floor rate of 2.75%. DHS was not in compliance with its minimum EBITDA covenant and quarterly capital expenditures limitation as of December 31, 2010. On January 1, 2011, DHS failed to pay its scheduled principal and interest payment and subsequently entered into a forbearance agreement more fully described in Note 20, "Subsequent Events."

The credit facility matures on August 31, 2011 and the debt is classified as a current liability in the December 31, 2010 consolidated balance sheet. The DHS facility is non-recourse to Delta.

On August 15, 2008, DHS entered into a new agreement with LCPI to amend its existing credit facility. The revised agreement increased the borrowing base from $75.0 million to $150.0 million. Total debt outstanding at December 31, 2009 under the facility was $83.3 million. Because of LCPI's bankruptcy and default, DHS did not have any additional borrowing capacity under the LCPI facility. Under the revised agreement, DHS had an obligation to provide to LCPI by March 31 of each year audited financial statements reported on without a going concern qualification or exception by the independent auditor. DHS was not able to provide audited financial statements not containing an explanatory paragraph related to its ability to continue as a going concern, and, accordingly, DHS was not in compliance with this covenant at March 31, 2009. On April 22, 2009, DHS entered into a Forbearance Agreement (the "DHS Forbearance"), as amended on May 21, 2009, with LCPI in which LCPI agreed to forbear until June 15, 2009 from exercising its rights and remedies under the credit agreement including, among other actions,

(7) Long-Term Debt, Continued

acceleration of all amounts due under the credit facility or foreclosure on the DHS rigs and other assets pledged as collateral, including accounts receivable. In conjunction with the DHS Forbearance, DHS paid a fee of $250,000 and made a $1.25 million prepayment on the facility. During the forbearance period, DHS must use 75% of any accounts receivable collected as well as proceeds from asset dispositions to pay down its credit facility. As of December 31, 2009, DHS had customer receivables of $23.8 million, $20.8 million of which were due from Delta and subsequently paid in 2010. At December 31, 2009, DHS was not in compliance with its minimum EBITDA, maximum leverage ratio, minimum interest coverage ratio, and minimum current ratio financial covenants. As a result of these events, the Company has classified the entire $83.3 million of debt outstanding under the DHS credit facility as a current liability in the accompanying consolidated balance sheet as of December 31, 2009. As a result of these events, DHS wrote off $643,000 of previously unamortized deferred financing costs related to its LCPI credit agreement during the three months ended June 30, 2009.

Maturities

Maturities of long-term debt, in thousands of dollars, based on contractual terms are as follows:

Year ending December 31,	
2011	$ 169,590
2012	144,130
2013	-
2014	-
2015	150,000
2016 and thereafter	-
Total	$ 463,720

(8) Stockholders' Equity

Preferred Stock

The Company has 3.0 million shares of preferred stock authorized, par value $0.01 per share, issuable from time to time in one or more series. As of December 31, 2010 and 2009, no preferred stock was outstanding. As part of the reincorporation on January 31, 2006, the Company reduced the par value of its preferred stock to $0.01 per share.

Common Stock

The Company has 600.0 million shares of common stock authorized, par value $0.01 per share, issuable at the discretion of the Company's Board of Directors. As of December 31, 2010 and 2009, there were 285.1 and 282.5 shares issued and outstanding, respectively, not counting shares that are held as treasury shares. An amendment to our Certificate of Incorporation to increase the number of authorized shares of the Company's authorized common stock from 300.0 million to 600.0 million was approved at a special meeting of stockholders held on December 22, 2009.

On February 20, 2008, the Company issued 36.0 million shares of the Company's common stock to Tracinda Corporation at $19.00 per share for net proceeds of $667.1 million (including a $5.0 million deposit on the transaction received in December 2007), representing approximately 35% of the Company's outstanding common stock at the time. In conjunction with the transaction, a finder's fee of 263,158 shares of common stock valued at $5.0 million based on the transaction's $19.00 per share price was issued to an unrelated third party.

Subsequent to this initial transaction, Tracinda acquired additional shares in the open market and participated in the May 2009 equity offering, described below. As a result, Tracinda currently owns approximately 33% of the Company's outstanding common stock.

(8) Stockholders' Equity, Continued

On May 13, 2009, the Company completed an underwritten offering of 172.5 million shares of the Company's common stock at $1.50 per share for net proceeds of $246.9 million, net of underwriting commissions and related offering expenses.

On December 22, 2009, the Company granted 5.7 million shares of non-vested restricted stock to employees of the Company. The shares vest in equal thirds on July 1, 2010, 2011, and 2012. In conjunction with the resignation of the Company's former Chairman and Chief Executive Officer, 1.0 million shares of common stock were issued pursuant to a severance agreement more fully described in Note 3, "Summary of Significant Accounting Policies – Executive Severance Agreements".

During the year ended December 31, 2010, the Company issued 480,778 fully vested shares to the non-employee members of the Board of Directors in consideration for their service on the Board for the year ended December 31, 2009 and also granted 5.1 million shares of non-vested restricted stock which vests in full on July 1, 2011 to certain employees.

Treasury Stock

During 2008, DHS implemented a retention bonus plan whereby certain key managers of DHS were granted shares of Delta common stock, one-third of which vest on each one year anniversary of the grant date. In addition, similar incentive grants were made to DHS executives during 2008. The shares of Delta common stock used to fund the grants are to be proportionally provided by Delta's issuance of new shares to DHS employees and Chesapeake's contribution to DHS of Delta shares purchased in the open market. The Delta shares contributed by Chesapeake are recorded at historical cost in the accompanying consolidated balance sheet as treasury stock and will be carried as such until the shares vest. The Delta shares contributed by Delta are treated as non-vested stock issued to employees and therefore recorded as additions to additional paid in capital over the vesting period. Compensation expense is recorded on all such grants over the vesting period.

Non-Qualified Stock Options - Directors and Employees

On December 22, 2009, the stockholders approved the Company's 2009 Performance and Equity Plan (the "2009 Plan"). Subject to adjustment as provided in the 2009 Plan, the number of shares of Common Stock that may be issued or transferred, plus the amount of shares of Common Stock covered by outstanding awards granted under the 2009 Plan, may not in the aggregate exceed 30 million. The 2009 Plan supplements the Company's 1993, 2001, 2004 and 2007 Incentive Plans. The purpose of the 2009 Plan is to provide incentives to selected employees and directors of the Company and its subsidiaries, and selected non-employee consultants and advisors to the Company and its subsidiaries, who contribute and are expected to contribute to the Company's success.

Incentive awards under the 2009 Plan may include non-qualified or incentive stock options, limited appreciation rights, tandem stock appreciation rights, phantom stock, stock bonuses or cash bonuses. Options issued to date under the Company's various incentive plans have been non-qualified stock options as defined in such plans.

(8) Stockholders' Equity, Continued

A summary of the stock option activity under the Company's various plans and related information for the year ended December 31, 2010 follows:

	Year Ended December 31, 2010			
	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding-beginning of year	1,427,750	$ 8.62		
Granted	250,000	0.79		
Exercised	-	-		
Expired	(69,750)	(3.75)		
Outstanding-end of year	1,608,000	$ 7.26	3.98 years	-
Exercisable-end of year	1,608,000	$ 7.26	3.98 years	-

The Company recognizes the cost of share based payments over the period during which the employee provides service. Exercise prices for options outstanding under the Company's various plans as of December 31, 2010 ranged from $0.79 to $15.34 per share and the weighted-average remaining contractual life of those options was 3.98 years. During 2010, 250,000 fully vested options were issued with an exercise price of $0.79 per share and $109,000 of related stock based compensation expense was recorded. No options were granted during the years ended December 31, 2009 and 2008. The total intrinsic value of options exercised during the years ended December 31, 2010, 2009, and 2008 were zero, zero, and $5.3 million, respectively.

A summary of the restricted stock (nonvested stock) activity under the Company's plan and related information for the year ended December 31, 2010 follows:

	Year Ended December 31, 2010			
	Nonvested Stock	Weighted-Average Grant-Date Fair Value	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Nonvested-beginning of year	7,171,066	$ 3.06		
Granted	5,653,546	0.75		
Vested	(3,323,154)	(2.70)		
Expired / Forfeited	(2,157,694)	(2.78)		
Nonvested-end of year	7,343,764	$ 1.53	0.88 years	$5,581,261

Stock Based Compensation

The Company recognized stock compensation included in general and administrative expense as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Stock options	$ 109	$ -	$ -
Non-vested stock	10,399	7,541	10,218
Performance shares	959	2,420	5,662
Total	$ 11,467	$ 9,961	$ 15,880

The total grant date fair value of restricted stock vested during the years ended December 31, 2010, 2009, and 2008 was $9.0 million, $12.7 million, and $6.2 million, respectively.

(8) Stockholders' Equity, Continued

At December 31, 2010, 2009, and 2008, the total unrecognized compensation cost related to the non-vested portion of restricted stock and stock options was $6.3 million, $16.5 million, and $22.2 million which is expected to be recognized over a weighted average period of 0.88, 2.33, and 2.37 years, respectively.

Cash received from exercises under all share-based payment arrangements for the years ended December 31, 2010, 2009, and 2008 was zero, zero, and $5.1 million, respectively. There were no tax benefits realized from the stock options exercised during the years ended December 31, 2010, 2009, and 2008. During the years ended December 31, 2010, 2009, and 2008 zero, zero, and $8.4 million, respectively, of tax benefits were generated from the exercise of stock options; however, such benefit will not be recognized in stockholders' equity until the period in which these amounts decrease current taxes payable.

(9) Employee Benefits

The Company adopted a profit sharing plan on January 1, 2002. All employees are eligible to participate and contributions to the profit sharing plan are voluntary and must be approved by the Board of Directors. Amounts contributed to the Plan vest over a six year service period.

For the years ended December 31, 2010, 2009 and 2008, the Company expensed zero, $49,000, and $914,000, respectively, related to its profit sharing plan.

The Company adopted a 401(k) plan effective May 1, 2005. All employees are eligible to participate and make employee contributions once they have met the plan's eligibility criteria. Under the 401(k) plan, the Company's employees make salary reduction contributions in accordance with the Internal Revenue Service guidelines. The Company's matching contribution is an amount equal to 100% of the employee's elective deferral contribution which cannot exceed 3% of the employee's compensation, and 50% of the employee's elective deferral which exceeds 3% of the employee's compensation but does not exceed 5% of the employee's compensation. The expense recognized in relation to the Company's 401(k) plan was $292,000, $165,000 and $513,000 in 2010, 2009 and 2008, respectively. The 401(k) matching contribution was suspended in April 2009, but was subsequently reinstated on January 1, 2010.

(10) Commodity Derivative Instruments

The Company periodically enters into commodity price risk transactions to manage its exposure to oil and gas price volatility. These transactions may take the form of futures contracts, collar agreements, swaps or options. The purpose of the hedges is to provide a measure of stability and predictability to the Company's future revenues and cash flows in an environment of volatile oil and gas prices. All transactions are accounted for in accordance with requirements of applicable FASB guidance. The Company recognizes mark-to-market gains and losses in current earnings.

During the first quarter of 2009, the Company was required by the terms of the existing credit facility to execute derivative contracts specified by the lenders at the time. During the fourth quarter of 2010, the Company was required in conjunction with its amended credit facility (see Note 7, "Long-term Debt") to execute additional derivative contracts to hedge a specified portion of anticipated oil and gas production through 2013.

At December 31, 2010, all of the Company's outstanding derivative contracts were fixed price swaps. Under the swap agreements, the Company receives the fixed price and pays the floating index price. The Company's swaps are settled in cash on a monthly basis. By entering into swaps, the Company effectively fixes the price that it will receive for the hedged production.

(10) Commodity Derivative Instruments, Continued

The following table summarizes the Company's open derivative contracts at December 31, 2010:

Commodity	Volume		Fixed Price	Term		Index Price	Net Fair Value Asset (Liability) at December 31, 2010 (In thousands)
Crude oil	500	Bbls / Day	$ 57.70	Jan '11	- Dec '11	NYMEX – WTI	(5,946)
Crude oil	116	Bbls / Day	$ 91.05	Jan '11	- Dec '11	NYMEX – WTI	(70)
Crude oil	497	Bbls / Day	$ 91.05	Jan '12	- Dec '12	NYMEX – WTI	(408)
Crude oil	396	Bbls / Day	$ 91.05	Jan '13	- Dec '13	NYMEX – WTI	(181)
Natural gas	12,000	MMBtu / Day	$ 5.150	Jan '11	- Dec '11	CIG	4,337
Natural gas	3,253	MMBtu / Day	$ 5.040	Jan '11	- Dec '11	CIG	1,047
Natural gas	347	MMBtu / Day	$ 4.440	Jan '11	- Dec '11	CIG	58
Natural gas	12,052	MMBtu / Day	$ 4.440	Jan '12	- Dec '12	CIG	(771)
Natural gas	10,301	MMBtu / Day	$ 4.440	Jan '13	- Dec '13	CIG	(1,059)
Total							$ (2,993)

The following table summarizes the fair values and location in the Company's consolidated balance sheet of all derivatives held by the Company as of December 31, 2010 (in thousands):

Derivatives Not Designated as Hedging Instruments	Balance Sheet Classification	Fair Value
Liabilities		
Commodity Swaps	Derivative Instruments – Current Liabilities, net	$ (574)
Commodity Swaps	Derivative Instruments – Long-Term Liabilities, net	(2,419)
Total		$ (2,993)

The following table summarizes the realized and unrealized losses and the classification in the consolidated statement of operations of derivatives not designated as hedging instruments for the year ended December 31, 2010 (in thousands):

Derivatives Not Designated as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives
Commodity Swaps	Realized Loss on Derivative Instruments, net – Other Income and (Expense)	$ (5,835)
Commodity Swaps	Unrealized Gain on Derivative Instruments, net – Other Income and (Expense)	$ 23,979
Total		$ 18,144

The net gains (losses) from all hedging activities recognized in the Company's statements of operations were $18.1 million, ($28.1 million), and $21.7 million for the years ended December 31, 2010, 2009 and 2008, respectively.

In January and February 2011, the Company entered into several natural gas liquid derivative contracts that are more fully described in Note 20, "Subsequent Events".

(11) Income Taxes

The Company accounts for income taxes in accordance with the provisions of ASC 740, "Accounting for Income Taxes." Income tax expense (benefit) attributable to income from continuing operations consisted of the following for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Current:			
U.S. - Federal	$ (67)	$ -	$ -
U.S. - State	-	-	-
Foreign	-	-	66
Deferred:			
U.S. - Federal	580	190	(11,235)
U.S. - State	30	25	(554)
Total	$ 543	$ 215	$ (11,723)

Income tax expense attributable to income from continuing operations was different from the amounts computed by applying U.S. Federal income tax rate of 35% to pretax income from continuing operations as a result of the following:

	Years Ended December 31,		
	2010	2009	2008
Federal statutory rate	(35.0)%	(35.0)%	(35.0)%
State income taxes, net of federal benefit	(1.9)	(1.9)	(1.9)
Change in valuation allowance	33.2	35.3	34.7
Other	4.2	1.7	(0.5)
Actual income tax rate	0.5%	0.1%	(2.7)%

(11) Income Taxes, Continued

Deferred tax assets (liabilities) are comprised of the following at December 31, 2010 and 2009 (in thousands):

	2010	2009
Deferred tax assets:		
Net operating loss	$ 314,480	$ 258,496
Capital loss carry forwards	27,964	-
Asset retirement obligation	1,896	4,242
Percentage depletion	73	597
Property and equipment	72,529	89,441
Equity compensation	7,912	7,823
Marketable securities	-	120
Equity investments	3,669	1,751
Derivative instruments	1,102	10,019
Minimum tax credit	1,152	1,221
Contribution carryforwards	517	512
Accrued bonuses	832	-
Allowance for doubtful accounts	856	38
Accrued vacation	85	173
Other	5	6
Total deferred tax assets	433,072	374,439
Valuation allowance	(417,236)	(354,652)
Net deferred tax assets	$ 15,836	$ 19,787
Deferred tax liabilities:		
Property and equipment	(15,484)	(19,390)
Prepaid insurance, marketable securities, and other	(352)	(397)
Total deferred tax liabilities	$ (15,836)	$ (19,787)

The Company has net operating loss carryovers as of December 31, 2010 of $884.6 million for federal income tax purposes and $854.1 million for financial reporting purposes. The difference of $30.5 million relates to tax deductions for compensation expense for financial reporting purposes for which the benefit will not be recognized until the related deductions reduce taxes payable.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future results of operations, and tax planning strategies in making this assessment. Based upon the level of historical taxable income, significant book losses during the year ended December 31, 2010, and projections for future results of operations over the periods in which the deferred tax assets are deductible, among other factors, management concluded during the second quarter of 2007 and continues to concluded that the Company does not meet the "more likely than not" requirement of ASC 740 in order to recognize deferred tax assets. Accordingly, for the year ended December 31, 2010, the Company recorded in income tax expense a valuation allowance of $62.5 million offsetting the Company's deferred tax assets.

(11) Income Taxes, Continued

At December 31, 2010, the Company had net operating loss carryforwards for regular and alternative minimum tax purposes as follows:

Regular tax net operating loss carryforwards	$ 884,627
Alternative minimum tax net operating loss carryforwards	835,321

If not utilized, the tax net operating loss carryforwards will expire during the period 2010 through 2030.

The Company's net operating losses are scheduled to expire as follows (in thousands):

2011	$ 5,939
2012	994
2013	868
2014	3,132
2015	106
2016 and thereafter	873,588
Total	$ 884,627

Effective January 1, 2007, the Company adopted applicable provisions of ASC 740 to recognize, measure, and disclose uncertain tax positions in the financial statements. Under ASC 740, tax positions must meet a "more-likely-than-not" recognition threshold at the effective date to be recognized upon the adoption and in subsequent periods. During the year ended December 31, 2010, no adjustments were recognized for uncertain tax benefits.

The Company recognizes interest and penalties related to uncertain tax positions in income tax (benefit)/expense. No interest and penalties related to uncertain tax positions were accrued as of December 31, 2010.

The tax years 2007 through 2009 for federal returns and 2006 through 2009 for state returns remain open to examination by the major taxing jurisdictions in which the Company operates.

(12) Related Party Transactions

Transactions with Directors, Officers and Affiliates

During fiscal 2001 and 2000, Mr. Larson and Mr. Parker, officers of the Company at the time, guaranteed certain borrowings which have subsequently been repaid. As consideration for the guarantee of the Company's indebtedness, each officer was assigned a 1% overriding royalty interest ("ORRI") in the properties acquired with the proceeds of the borrowings. Each of Mr. Larson and Mr. Parker earned approximately $91,000, $67,000, and $154,000, for their respective 1% ORRI during the years ended December 31, 2010, 2009 and 2008, respectively. In addition, in December 1999, Mr. Larson and Mr. Parker, officers of the Company at the time, guaranteed certain other borrowings which have subsequently been repaid, the proceeds of which were utilized by the Company to purchase interests in certain Offshore California leases that later became the subject of litigation with the United States. As consideration for the guarantee of the Company's indebtedness, each officer was assigned a 1% overriding royalty interest in the properties acquired with the proceeds of the borrowings, as well as a 1% overriding royalty interest in compensation received for the properties from the United States. Because the Company received payments from the United States with respect to these leases as a result of the conclusion of its Offshore California litigation (See Note 15, "Commitments and Contingencies"), each of Mr. Larson and Mr. Parker received approximately $814,341 during the year ended December 31, 2009 pursuant to the terms of his agreement with the Company. As a result of the litigation, the Company no longer owns any interest in the Offshore California leases.

During May 2009, subsequent to receipt of the offshore litigation award related to the Amber Case, the Company purchased for $26.0 million contingent payment rights previously sold to Tracinda Corporation for $25.0 million that entitled Tracinda to receive up to $27.9 million of the litigation proceeds related to the Amber Case.

(12) Related Party Transactions, Continued

Accounts Receivable Related Parties

At December 31, 2010 and 2009, the Company had $14,000 and $15,000 of receivables from related parties, respectively. These amounts include drilling costs and lease operating expenses on wells owned by the related parties and operated by the Company.

(13) Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share (in thousands, except per share amounts):

	Years Ended December 31,		
	2010	2009	2008
Net loss attributable to Delta common stockholders	$ (182,332)	$ (328,783)	$ (456,064)
Basic weighted-average shares outstanding	275,042	211,033	95,530
Add: dilutive effects of stock options and unvested stock grants	-	-	-
Diluted weighted-average common shares outstanding	275,042	211,033	95,530
Basic net loss per common share	$ (0.66)	$ (1.56)	$ (4.77)
Diluted net loss per common share	$ (0.66)	$ (1.56)	$ (4.77)

Potentially dilutive securities excluded from the calculation of diluted shares outstanding include the following (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Stock issuable upon conversion of convertible notes	3,790	3,790	3,790
Stock options	1,608	1,427	1,528
Non-vested restricted stock	7,344	7,171	2,023
Total potentially dilutive securities	12,742	12,388	7,341

(14) Guarantor Financial Information

On March 15, 2005, Delta issued $150.0 million of 7% Senior Notes ("Senior Notes") that mature in 2015. In addition, on April 25, 2007, the Company issued $115.0 million of 3¾% Convertible Senior Notes due in 2037 ("Convertible Notes"). Both the Senior Notes and the Convertible Notes are guaranteed by all of the Company's other wholly-owned subsidiaries ("Guarantors"). Each of the Guarantors, fully, jointly and severally, irrevocably and unconditionally guarantees the performance and payment when due of all the obligations under the Senior Notes and the Convertible Notes. DHS, CRBP, PGR (through the closing date of the Wapiti Transaction), and Amber ("Non-guarantors") are not guarantors of the indebtedness under the Senior Notes or the Convertible Notes.

The following financial information sets forth the Company's condensed consolidated balance sheets as of December 31, 2010, and 2009, the condensed consolidated statements of operations for the years ended December 31, 2010, 2009 and 2008, and the condensed consolidated statements of cash flows for the years ended December 31, 2010, 2009 and 2008 (in thousands). For purposes of the condensed financial information presented below, the equity in the earnings or losses of subsidiaries is not recorded in the financial statements of the issuer.

Condensed Consolidated Balance Sheet
December 31, 2010

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 130,252	$ 322	$ 16,232	$ -	$ 146,806
Property and equipment:					
Oil and gas properties	1,083,005	-	19,215	(117)	1,102,103
Drilling rigs and trucks	594	-	174,086	-	174,680
Other	74,740	32,676	1,781	-	109,197
Total property and equipment	1,158,339	32,676	195,082	(117)	1,385,980
Accumulated depletion, depreciation and amortization	(371,622)	(28,762)	(117,030)	-	(517,414)
Net property and equipment	786,717	3,914	78,052	(117)	868,566
Investment in subsidiaries	1,092	-	-	(1,092)	-
Other long-term assets	6,207	2,407	126	-	8,740
Total assets	$ 924,268	$ 6,643	$ 94,410	$ (1,209)	$ 1,024,112
Current liabilities	$ 136,965	$ (26)	$ 81,823	$ -	$ 218,762
Long-term liabilities					
Long-term debt, derivative instruments and deferred taxes	288,025	1,801	-	-	289,826
Asset retirement obligation and other liabilities	3,929	-	-	-	3,929
Total long-term liabilities	291,954	1,801	-	-	293,755
Total Delta stockholders' equity	498,201	4,868	12,587	(1,209)	514,447
Non-controlling interest	(2,852)	-	-	-	(2,852)
Total equity	495,349	4,868	12,587	(1,209)	511,595
Total liabilities and equity	$ 924,268	$ 6,643	$ 94,410	$ (1,209)	$ 1,024,112

(14) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Operations
Year Ended December 31, 2010

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 93,516	$ 77	$ 54,006	$ (794)	$ 146,805
Operating expenses:					
Oil and gas expense	43,504	-	-	-	43,504
Exploration expense	1,337	-	-	-	1,337
Dry hole costs and impairments	38,092	4,894	586	-	43,572
Depreciation and depletion	58,263	2	20,028	(64)	78,229
Drilling and trucking operating expenses	-	-	42,861	(613)	42,248
General and administrative	35,221	54	5,855	-	41,130
Executive severance expense	(674)	-	-	-	(674)
Total operating expenses	175,743	4,950	69,330	(677)	249,346
Operating loss	(82,227)	(4,873)	(15,324)	(117)	(102,541)
Other income and expenses	(10,151)	34	(8,657)	-	(18,774)
Income tax expense	(543)	-	-	-	(543)
Discontinued operations	20,834	(133)	(92,857)	-	(72,156)
Net loss	(72,087)	(4,972)	(116,838)	(117)	(194,014)
Less loss attributable to non-controlling interest	11,682	-	-	-	11,682
Net loss attributable to Delta common stockholders	$ (60,405)	$ (4,972)	$ (116,838)	$ (117)	$ (182,332)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2010

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash provided by (used in):				
Operating activities	$ (48,918)	$ (635)	$ 18,015	$ (31,538)
Investing activities	202,049	622	(4,833)	197,838
Financing activities	(198,510)	-	(14,055)	(212,565)
Net decrease in cash and cash equivalents	(45,379)	(13)	(873)	(46,265)
Cash at beginning of the period	58,533	74	3,311	61,918
Cash at the end of the period	$ 13,154	$ 61	$ 2,438	$ 15,653

(14) Guarantor Financial Information, Continued

Condensed Consolidated Balance Sheet
December 31, 2009

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 160,408	$ 448	$ 31,596	$ -	$ 192,452
Property and equipment:					
Oil and gas properties	1,529,920	592	130,837	(585)	1,660,764
Drilling rigs and trucks	594	-	177,168	-	177,762
Other	73,383	32,916	1,919	-	108,218
Total property and equipment	1,603,897	33,508	309,924	(585)	1,946,744
Accumulated depletion, depreciation and amortization	(652,432)	(24,040)	(124,029)	-	(800,501)
Net property and equipment	951,465	9,468	185,895	(585)	1,146,243
Investment in subsidiaries	80,058	-	-	(80,058)	-
Other long-term assets	114,820	3,787	183	-	118,790
Total assets	$ 1,306,751	$ 13,703	$217,674	$ (80,643)	$ 1,457,485
Current liabilities	$ 179,302	$ 319	$ 92,579	$ -	$ 272,200
Long-term liabilities					
Long-term debt, derivative instruments and deferred taxes	478,710	1,801	-	-	480,511
Asset retirement obligation and other liabilities	7,358	11	285	-	7,654
Total long-term liabilities	486,068	1,812	285	-	488,165
Total Delta stockholders' equity	632,843	11,572	124,810	(80,643)	688,582
Non-controlling interest	8,538	-	-	-	8,538
Total equity	641,381	11,572	124,810	(80,643)	697,120
Total liabilities and equity	$ 1,306,751	$ 13,703	$217,674	$ (80,643)	$ 1,457,485

(14) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Operations
Year Ended December 31, 2009

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 159,544	$ (3,020)	$ 16,663	$ (2,984)	$ 170,203
Operating expenses:					
Oil and gas expense	39,528	-	-	-	39,528
Exploration expense	2,604	-	-	-	2,604
Dry hole costs and impairments	174,975	1,896	6,508	-	183,379
Depreciation and depletion	81,111	223	23,497	(579)	104,252
Drilling and trucking operating expenses	1	-	17,114	(1,822)	15,293
General and administrative	37,114	75	4,225	-	41,414
Executive severance expense	3,739	-	-	-	3,739
Total operating expenses	339,072	2,194	51,344	(2,401)	390,209
Operating loss	(179,528)	(5,214)	(34,681)	(583)	(220,006)
Other expenses	(87,202)	(33)	(7,857)	-	(95,092)
Income tax (expense) benefit	(1,009)	-	794	-	(215)
Discontinued operations	(23,400)	110	(11,081)	-	(34,371)
Net loss	(291,139)	(5,137)	(52,825)	(583)	(349,684)
Less loss attributable to non-controlling interest	20,901	-	-	-	20,901
Net loss attributable to Delta common stockholders	$ (270,238)	$ (5,137)	$ (52,825)	$ (583)	$ (328,783)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2009

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash provided by (used in):				
Operating activities	$ 79,428	$ (2,736)	$ 4,452	$ 81,144
Investing activities	(53,980)	2,659	3,954	(47,367)
Financing activities	(26,838)	-	(10,496)	(37,334)
Net decrease in cash and cash equivalents	(1,390)	(77)	(2,090)	(3,557)
Cash at beginning of the period	60,993	151	4,331	65,475
Cash at the end of the period	$ 59,603	$ 74	$ 2,241	$ 61,918

(14) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Operations
Year Ended December 31, 2008

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 192,816	$ -	$ 100,518	$ (51,074)	$ 242,260
Operating expenses:					
Oil and gas expense	47,006	-	-	-	47,006
Exploration expense	10,975	-	-	-	10,975
Dry hole costs and impairments	389,634	21,469	29,349	-	440,452
Depreciation and depletion	79,933	285	23,436	(9,302)	94,352
Drilling and trucking operating expenses	-	-	62,422	(29,828)	32,594
General and administrative	48,145	71	5,391	-	53,607
Total operating expenses	575,693	21,825	120,598	(39,130)	678,986
Operating loss	(382,877)	(21,825)	(20,080)	(11,944)	(436,726)
Other income and expenses	(16,267)	40	(11,077)	11,860	(15,444)
Income tax benefit	3,580	-	8,143	-	11,723
Discontinued operations	(30,980)	569	3,308	-	(27,103)
Net loss	(426,544)	(21,216)	(19,706)	(84)	(467,550)
Less loss attributable to non-controlling interest	11,486	-	-	-	11,486
Net loss attributable to Delta common stockholders	$ (415,058)	$ (21,216)	$ (19,706)	$ (84)	$ (456,064)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2008

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash provided by (used in):				
Operating activities	$ 120,043	$ 669	$ 19,964	$ 140,676
Investing activities	(869,588)	(32,844)	(80,184)	(982,616)
Financing activities	805,881	32,019	59,722	897,622
Net increase (decrease) in cash and cash equivalents	56,336	(156)	(498)	55,682
Cash at beginning of the period	4,657	307	4,829	9,793
Cash at the end of the period	$ 60,993	$ 151	$ 4,331	$ 65,475

(15) Commitments and Contingencies

The Company leases office space in Denver, Colorado and certain other locations in the states in which the Company operates and also leases equipment and autos under non-cancelable operating leases. Rent expense for the years ended December 31, 2010, 2009 and 2008, was approximately $1.1 million, $1.7 million, and $1.6 million, respectively. The following table summarizes the future minimum payments under all non-cancelable operating lease obligations (in thousands):

2011	1,596
2012	1,444
2013	1,431
2014	1,490
2015	264
2016 and thereafter	682
Total	$ 6,907

The Company has agreements with its three executive officers which provide for severance payments equal to three times the average of the officer's combined annual salary and bonus, benefits continuation and accelerated vesting of options and stock grants in the event that there is a change in control of the Company. These agreements were amended on December 29, 2010 to bring them into compliance with Section 409A of the Internal Revenue Code.

Offshore Litigation

On December 16, 2009 the Company entered into a settlement agreement with the United States of America with respect to its breach of contract claim against the United States in the case of Amber Resources Co., et al. v. United States, Civ. Act. No. 2-30 that was filed in the United States Court of Federal Claims with respect to Lease OCS P-452. On February 25, 2009, the Court of Federal Claims entered a judgment in the Company's favor in the amount of $91.4 million with respect to its claim to recover lease bonus payments for Lease 452. On April 24, 2009, the government filed a notice of appeal of this judgment, but never filed an opening brief pending the outcome of settlement discussions. Under the terms of the settlement agreement the Company received gross proceeds of $65.0 million, which resulted in net proceeds to it of approximately $50.0 million after making all contingent payments to third parties. An order of dismissal was entered by the United States Court of Appeals for the Federal Circuit on January 12, 2010 which concluded the litigation.

The Company formerly owned a 2.41934% working interest in OCS Lease 320 in the Sword Unit, Offshore California, and Amber formerly owned a 0.97953% working interest in the same lease. Lease 320 was conveyed back to the United States at the conclusion of the Amber litigation when the courts determined that the government had breached that lease (among others) and was liable to the working interest owners for damages; however, the government now contends that the former working interest owners are still obligated to permanently plug and abandon an exploratory well that was drilled on the lease and to clear the well site. The former operator of the lease has commenced litigation against the United States seeking a declaratory judgment that the former working interest owners are not responsible for these costs as a result of the government's breach of the lease. It is currently unknown whether or not the litigation will be successful, or what the costs of decommissioning the well would be if the former working interest owners are ultimately held liable.

Shareholder Derivative Suit

On January 12, 2010 an Order of Dismissal was entered in the Tenth Circuit Court of Appeals which concluded the shareholders' derivative options backdating litigation entitled Britton v. Parker, et al. The Order was entered pursuant to a Motion to Dismiss that was filed by the Plaintiffs after the parties reached a settlement agreement on November 6, 2009. On September 23, 2009, the United States District Court for the District of Colorado had entered an opinion and order dismissing the Plaintiff's Complaint, but on October 22, 2009, the Plaintiffs filed a Notice of Appeal with the United States Court of Appeals for the Tenth Circuit. Pursuant to the terms of the settlement

(15) Commitments and Contingencies, Continued

agreement, the Plaintiffs/appellants agreed to file a motion to voluntarily dismiss, with prejudice, the appeal, and the parties agreed that that each party would bear its own costs and no award of costs would be made to either party. In addition, the parties agreed that no party to the litigation would contend that any other party or its counsel had brought frivolous litigation in violation of the Federal Rules of Civil Procedure.

212 Resources

During the previous quarter the Company was engaged in an arbitration with 212 Resources Corporation ("212") that was filed with the American Arbitration Association on October 27, 2009. The matter was set for arbitration on January 24, 2011, but was ultimately settled pursuant to a final Settlement Agreement executed by the parties on January 25, 2011, which required the Company to pay $1.5 million to 212 in consideration of mutual releases of claims and the termination of the underlying agreement.

DHS Rig Matter

The Company's indirect, 49.8% owned affiliate DHS and certain of its employees, among others, have been notified by the Office of the Inspector General, Office of Investigations, of the Export-Import Bank of the United States, and the U.S. Department of Justice, that the Company and certain of its employees are the subject of an investigation in connection with a loan guarantee sought from the Export-Import Bank in the first quarter of 2010 of a loan from a Mexican bank sought by a DHS customer in Mexico. DHS has cooperated and will continue to cooperate with the investigation, which is currently in its initial stages. This investigation is subject to uncertainties, and, as such, DHS is unable to estimate the nature of any possible liability that may result.

(16) Business Segments

The Company has two reportable segments: oil and gas exploration and production ("Oil and Gas") and drilling operations ("Drilling") through its ownership in DHS. Following is a summary of segment results for the years ended December 31, 2010, 2009 and 2008.

	Oil and Gas	Drilling	Inter-segment Eliminations	Consolidated
		(In thousands)		
Year Ended December 31, 2010				
Revenues from external customers	$ 93,593	$ 53,212	$ -	$ 146,805
Inter-segment revenues	-	794	(794)	-
Total revenues	93,593	54,006	(794)	146,805
Operating income (loss)	(87,805)	(14,619)	(117)	(102,541)
Other income and (expense) [1]	(10,112)	(8,662)	-	(18,774)
Loss from continuing operations, before tax	$ (97,917)	$(23,281)	$ (117)	$ (121,315)
Year Ended December 31, 2009				
Revenues from external customers	$ 156,523	$ 13,680	$ -	$ 170,203
Inter-segment revenues	-	2,984	(2,984)	-
Total revenues	156,523	16,664	(2,984)	170,203
Operating loss	(184,838)	(34,584)	(584)	(220,006)
Other income and (expense) [1]	(87,229)	(7,863)	-	(95,092)
Loss from continuing operations, before tax	$ (272,067)	$(42,447)	$ (584)	$ (315,098)
Year Ended December 31, 2008				
Revenues from external customers	$ 192,815	$ 49,445	$ -	$ 242,260
Inter-segment revenues	-	51,074	(51,074)	-
Total revenues	192,815	100,519	(51,074)	242,260
Operating loss	(404,829)	(19,953)	(11,944)	(436,726)
Other income and (expense) [1]	(16,221)	(11,083)	11,860	(15,444)
Loss from continuing operations, before tax	$ (421,050)	$(31,036)	$ (84)	$ (452,170)
December 31, 2010				
Total Assets	$ 1,016,509	$ 74,219	$(66,616)	$ 1,024,112
December 31, 2009				
Total Assets	$ 1,419,754	$ 104,287	$(66,556)	$ 1,457,485

[1] Includes interest and financing costs, gain on sale of marketable securities, unrealized losses on derivative contracts and other miscellaneous income for Oil and Gas, and other miscellaneous income for Drilling. Non-controlling interest is included in inter-segment eliminations.

(17) Selected Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share amounts)			
Year Ended December 31, 2010				
Total revenue	$ 39,104	$ 35,855	$ 35,438	$ 36,408
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	(10,676)	(55,610)	(18,676)	(36,353)
Net income (loss)	(12,797)	(149,750)	13,942	(33,727)
Net income (loss) per common share: (1)				
Basic	$ (0.05)	$ (0.54)	$ 0.05	$ (0.12)
Diluted	$ (0.05)	$ (0.54)	$ 0.05	$ (0.12)
Year Ended December 31, 2009				
Total revenue	$ 55,091	$ 20,658	$ 21,447	$ 73,007
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	(24,555)	(173,233)	(96,235)	(21,075)
Net income (loss)	(25,554)	(172,318)	(96,827)	(34,084)
Net income (loss) per common share: (1)				
Basic	$ (0.25)	$ (0.89)	$ (0.35)	$ (0.12)
Diluted	$ (0.25)	$ (0.89)	$ (0.35)	$ (0.12)

(1) The sum of individual quarterly net income per share may not agree with year-to-date net income per share as each period's computation is based on the weighted average number of common shares outstanding during the period.

(18) Disclosures About Capitalized Costs, Costs Incurred (Unaudited)

Capitalized costs related to oil and gas activities are as follows (in thousands):

	December 31, 2010	December 31, 2009	December 31, 2008
Unproved properties	$ 230,117	$ 280,844	$ 415,573
Proved properties	871,986	1,379,920	1,365,440
	1,102,103	1,660,764	1,781,013
Accumulated depreciation and depletion	(360,577)	(661,851)	(548,618)
Total	$ 741,526	$ 998,913	$ 1,232,395

Costs incurred in oil and gas activities are as follows (in thousands):

	December 31, 2010	December 31, 2009	December 31, 2008
Unproved property acquisition costs	$ 909	$ 2,083	$ 180,149
Proved property acquisition costs	-	-	41,666
Development costs incurred on proved undeveloped reserves	6,477	15,556	123,999
Development costs - other	35,883	43,892	261,588
Exploration and dry hole costs	1,423	36,216	122,827
Total	$ 44,692	$ 97,747	$ 730,229

Included in costs incurred are asset retirement obligation costs for all periods presented.

Changes in capitalized exploratory well costs are as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Balance at beginning of year	$ -	$ 13,812	$ 44,091
Additions to capitalized exploratory well costs pending the determination of proved reserves	6,200	-	12,397
Exploratory well costs included in property divestitures	-	-	(1,677)
Reclassified to proved oil and gas properties based on the determination of proved reserves	-	-	(563)
Capitalized exploratory well costs charged to dry hole expense	-	(13,812)	(40,436)
Balance at end of year	$ 6,200	$ -	$ 13,812
Exploratory well costs capitalized for one year or less after after completion of drilling	6,200	-	13,812
Exploratory well costs capitalized for greater than one year after completion of drilling	-	-	-
Balance at end of year	$ 6,200	$ -	$ 13,812

The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same period.

During 2009, the Company declared its exploratory Columbia River Basin well a dry hole and accordingly, at December 31, 2009, the Company had no remaining capitalized exploratory well costs. During 2010, the Company spud a deep test well in the Vega area to explore the Company's Piceance leasehold below the currently productive Williams Fork zone. Completion activities on the well began in February 2011.

(18) Disclosures About Capitalized Costs, Costs Incurred (Unaudited), Continued

A summary of the results of operations for oil and gas producing activities, excluding general and administrative cost, is as follows:

	Years Ended December 31,		
	2010	2009	2008
Revenue:			
Oil and gas revenues	$ 94,388	$ 82,723	$192,815
Expenses:			
Production costs	43,504	39,528	47,006
Depletion and amortization	55,402	78,772	78,019
Exploration	1,337	2,604	10,975
Abandoned and impaired properties	43,486	143,259	299,252
Dry hole costs	86	33,612	111,851
Results of operations of oil and gas producing activities	$ (49,427)	$ (215,052)	$(354,288)
Loss from operations of properties sold, net	(101,134)	(34,371)	(27,821)
Gain on sale of properties	28,978	-	718
Loss from results of discontinued operations of oil and gas producing activities	$ (72,156)	$ (34,371)	$ (27,103)

(19) Information Regarding Proved Oil and Gas Reserves (Unaudited)

There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. Crude oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered.

Recent SEC and FASB Rule-Making Activity. In December 2008, the SEC approved new rules designed to modernize oil and gas reserve reporting requirements. In addition, in January 2010 the FASB issued Accounting Standards Update 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the SEC rules. The Company adopted these rules effective December 31, 2009 and the rule changes, including those related to pricing and technology, are included in its reserves estimates.

Proved Oil and Gas Reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; i.e., prices as of the date the estimate was made for the years ended December 31, 2007 and 2008 and using the 12-month historical first of month average price for the years ended December 31, 2010 and 2009, and costs as of the date the estimate was made for all years presented. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(19) Information Regarding Proved Oil and Gas Reserves (Unaudited), Continued

(i) Reservoirs are considered proved if economic producability is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves;" (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids that may occur in underlaid prospects; and (D) crude oil, natural gas, and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other un-drilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

“Prepared” reserves are those quantities of reserves which were prepared by an independent petroleum consultant. “Audited” reserves are those quantities of revenues which were estimated by the Company’s employees and audited by an independent petroleum consultant. An audit is an examination of a company’s proved oil and gas reserves and net cash flow by an independent petroleum consultant that is conducted for the purpose of expressing an opinion as to whether such estimates, in aggregate, are reasonable and have been determined using methods and procedures widely accepted within the industry and in accordance with SEC rules.

Estimates of the Company’s oil and natural gas reserves and present values as of December 31, 2010, 2009, and 2008 were prepared by Ralph E. Davis Associates, Inc., the Company’s independent reserve engineers.

(19) Information Regarding Proved Oil and Gas Reserves (Unaudited), Continued

A summary of changes in estimated quantities of proved reserves for the years ended December 31, 2010, 2009, and 2008 is as follows (in thousands):

	Gas (MMcf)	Oil (MBbl)	Total (MMcfe)
Estimated Proved Reserves: Balance at December 31, 2007	309,473	11,025	375,623
Revisions of quantity estimate [1]	191,002	(4,108)	166,354
Extensions and discoveries [2]	152,801	1,652	162,713
Purchase of properties [3]	193,351	1,877	204,613
Sale of properties	-	-	-
Production	(18,950)	(993)	(24,908)
Estimated Proved Reserves: Balance at December 31, 2008	827,677	9,453	884,395
Revisions of quantity estimate [4]	(701,626)	(3,985)	(725,536)
Extensions and discoveries [5]	19,607	129	20,381
Purchase of properties	-	-	-
Sale of properties [6]	(1,375)	(354)	(3,499)
Production	(17,591)	(761)	(22,156)
Estimated Proved Reserves: Balance at December 31, 2009	126,692	4,482	153,585
Revisions of quantity estimate [7]	15,123	(111)	14,456
Extensions and discoveries [8]	21,132	172	22,164
Purchase of properties	-	-	-
Sale of properties [9]	(26,598)	(2,107)	(39,240)
Production	(13,670)	(516)	(16,766)
Estimated Proved Reserves: Balance at December 31, 2010	122,679	1,920	134,199
Proved developed reserves:			
December 31, 2008	161,552	3,274	181,196
December 31, 2009	115,004	2,977	132,866
December 31, 2010	112,534	1,859	123,688
Proved undeveloped reserves:			
December 31, 2008	666,125	6,179	703,199
December 31, 2009	11,688	1,505	20,719
December 31, 2010	10,145	61	10,511

Base Pricing, before adjustments for contractual differentials:

	CIG per Mmbtu	WTI per Bbl
December 31, 2008	$4.51	$44.60
December 31, 2009	$3.03	$61.18
December 31, 2010	$3.95	$79.61

Proved reserves were required to be calculated based on single day end of period prices for the year ended December 31, 2008. For 2009 and 2010, proved reserves were calculated based on the 12-month, first day of the month historical average price in accordance with new SEC rules. The prices shown above are base index prices to which adjustments are made for contractual deducts and other factors.

(1) The 2008 positive revisions were primarily related to 10-acre downspacing of the Company's Piceance Basin proved undeveloped reserves.

(2) The 2008 increase in proved reserves was primarily comprised of Rocky Mountain proved reserve increases primarily from the Company's Piceance Basin drilling program and related offset wells.

(3) During 2008, the Company purchased incremental interests in its existing Piceance Basin acreage and acquired new interests in adjacent leasehold to expand its Vega Area. See Note 4, "Oil and Gas Properties – Year Ended December 31, 2008 Acquisitions" for a description of the February 2008 transaction with EnCana.

(19) Information Regarding Proved Oil and Gas Reserves (Unaudited), Continued

(4) The 2009 negative revisions were primarily related to the loss of Piceance Basin undeveloped reserves as a result of lower pricing from utilizing the 12-month historical average required by the new SEC rules for use in the December 31, 2009 reserve report and the Company's more limited capital development plan at the time based on capital resources.

(5) The 2009 increase in proved reserves was primarily comprised of Rocky Mountain proved reserve increases primarily from the Company's Piceance Basin drilling program and related offset wells.

(6) During 2009, proved reserves located in various states were sold in a series of transactions described in Note 4, "Oil and Gas Properties – Year Ended December 31, 2009 – Divestitures."

(7) During 2010, revisions consists primarily of increased Piceance Basin proved reserves from the incorporation of improved fracturing technology, partially offset by Gulf Coast proved undeveloped reserves removed as a result of drilling plan modifications in conjunction with the Wapiti Transaction.

(8) During 2010, extensions and discoveries related primarily to Piceance locations added as proved reserves in 2010 offset to wells previously drilled.

(9) During 2010, proved reserves located in Texas, Colorado, and Wyoming were sold in conjunction with the Wapiti Transaction described in Note 4, "Oil and Gas Properties – Year Ended December 31, 2010 – Divestitures."

Future net cash flows presented below are computed using applicable prices (as summarized above) and costs and are net of all overriding royalty revenue interests.

	2010	2009	2008
		(in thousands)	
Future net cash flows	$ 793,556	$ 662,029	$ 3,542,332
Future costs:			
Production	402,334	125,108	924,705
Development and abandonment	18,899	77,965	1,337,842
Income taxes[1]	-	-	-
Future net cash flows	372,323	458,956	1,279,785
10% discount factor	(180,229)	(302,272)	(1,120,417)
Standardized measure of discounted future net cash flows	$ 192,094	$ 156,684	$ 159,368
Estimated future development cost anticipated for following two years on existing properties	$ 13,952	$ 59,313	$ 216,293

[1] No income tax provision is included in the standardized measure calculation shown above as the Company does not project to be taxable or pay cash income taxes based on its available tax assets and additional tax assets generated in the development of its reserves because the tax basis of its oil and gas properties and NOL carryforwards exceeds the amount of discounted future net earnings.

The principal sources of changes in the standardized measure of discounted net cash flows during the years ended December 31, 2010, 2009 and 2008 are as follows (in thousands):

	Years Ended December 31,		
	2010	2009	2008
Beginning of the year	$ 156,684	$ 159,368	$ 701,874
Sales of oil and gas production during the period, net of production costs	(55,755)	(48,195)	(164,755)
Purchase of reserves in place	-	-	289,040
Net change in prices and production costs	96,145	(64,282)	(907,844)
Changes in estimated future development costs	10,395	741,318	(27,087)
Extensions, discoveries and improved recovery	20,687	17,509	242,079
Revisions of previous quantity estimates, estimated timing of development and other	26,508	(674,560)	(281,302)
Previously estimated development and abandonment costs incurred during the period	6,477	15,556	123,999
Sales of reserves in place	(84,715)	(5,967)	-
Change in future income tax	-	-	113,177
Accretion of discount	15,668	15,937	70,187
End of year	$ 192,094	$ 156,684	$ 159,368

(20) Subsequent Events

During the previous quarter the Company was engaged in an arbitration with 212 Resources Corporation ("212") that was filed with the American Arbitration Association on October 27, 2009. The matter was set for arbitration on January 24, 2011, but was ultimately settled pursuant to a final Settlement Agreement executed by the parties on January 25, 2011, which required the Company to pay $1.5 million to 212 in consideration of mutual releases of claims and the termination of the underlying agreement.

DHS did not pay its scheduled principal and interest payment on January 1, 2011 and, as a result, subsequently entered into a Forbearance Agreement that currently expires on March 25, 2011. Subsequent to year-end, the Board of Directors of DHS engaged transaction advisors to commence a strategic alternatives process, focused on a sale of the company or substantially all of its assets. There can be no assurance that the terms offered by a potential buyer, if any, will be acceptable to the DHS shareholders. Additionally, the consummation of certain transactions are subject to the approval of DHS's senior lender and the proceeds received will be required to be used to pay down amounts outstanding under its DHS credit facility.

In January and February 2011, the Company entered into natural gas liquids derivative contracts that established a set commodity price for the hedged portion of its anticipated production as shown below:

		2011		2012		2013	
Commodity	Index Price	Volume (Mgl)	Price	Volume (Mgl)	Price	Volume (Mgl)	Price
Isobutane	Mont Belvieu-OPIS	659	$ 1.61	559	$ 1.52	224	$ 1.44
Normal Butane	Mont Belvieu-OPIS	790	1.56	671	1.49	269	1.41
Natural Gasoline	Mont Belvieu-OPIS	1,317	2.06	1,118	2.02	448	1.93
Propane	Mont Belvieu-OPIS	2,897	1.18	2,459	1.08	987	0.98
Purity Ethane	Mont Belvieu-OPIS	7,507	0.48	6,370	0.40	2,556	0.36
Total		13,170	$ 0.91	11,177	$ 0.83	4,484	$ 0.77

On March 14, 2011, the Company entered into an amendment to the MBL Credit Agreement that increased the availability under the term loan at the time from $6.2 million to $25.0 million, and doesn't require repayments of the term loan until the January 2012 maturity date. Specifically, among other changes, the amendment provided for an increase in the term loan commitment from $20.0 million to $25.0 million and removed the requirement that advances under the term loan be subject to approval of a development plan. In addition, so long as Delta is not in default under the MBL Credit Agreement, Delta is not required to comply with certain cash management provisions, including the previous requirement to repay any term loan advances outstanding on a monthly basis with 100% of net operating cash flows. As a result of the amendment, amounts outstanding under the term loan bear interest at prime plus 9.5% through September 30, 2011 and prime plus 11.0% thereafter for prime rate advances and at LIBOR plus 10.5% for LIBOR advances through September 30, 2011 and LIBOR plus 12% thereafter for LIBOR advances.

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Glossary of Oil and Gas Terms

The terms defined in this section are used throughout this Form 10-K.

Bbl. Barrel (of oil or natural gas liquids).

Bcf. Billion cubic feet (of natural gas).

Bcfe. Billion cubic feet equivalent.

Bbtu. One billion British Thermal Units.

Completion. Installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

Developed acreage. The number of acres which are allocated or held by producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole; dry well. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Equivalent volumes. Equivalent volumes are computed with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

Exploratory well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

HBP. Held by production.

Liquids. Describes oil, condensate, and natural gas liquids.

MBbls. Thousands of barrels.

Mcf. Thousand cubic feet (of natural gas).

Mcfe. Thousand cubic feet equivalent.

Mgl. Thousand gallons (of natural gas liquids).

MMBtu. One million British Thermal Units, a common energy measurement.

MMcf. Million cubic feet.

MMcfe. Million cubic feet equivalent.

MMgl. Million gallons.

NGL. Natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers.

NYMEX. New York Mercantile Exchange.

Present value or PV10% or "SEC PV10%." When used with respect to oil and gas reserves, present value or PV10% or SEC PV10% means the estimated future gross revenue to be generated from the production of net proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service, accretion, and future income tax expense or to depreciation, depletion, and amortization, discounted using monthly end-of-period discounting at a nominal discount rate of 10% per annum.

Productive wells. Producing wells and wells that are capable of production, including injection wells, salt water disposal wells, service wells, and wells that are shut-in.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids which, upon analysis of geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Estimated proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

Undeveloped acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains estimated proved reserves.

Working interest. An operating interest which gives the owner the right to drill, produce, and conduct operating activities on the property and a share of production.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange of Act of 1934, we have caused this Form 10-K to be signed on our behalf by the undersigned, thereunto duly authorized, in the City of Denver and State of Colorado on the 16th day of March, 2011.

DELTA PETROLEUM CORPORATION

By: /s/ Carl E. Lakey
Carl E. Lakey, President and Chief Executive Officer

By: /s/ Kevin K. Nanke
Kevin K. Nanke, Treasurer and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Form 10-K has been signed below by the following persons on our behalf and in the capacities and on the dates indicated.

Signature and Title	Date
/s/ Hank Brown Hank Brown, Director	March 16, 2011
/s/ Kevin R. Collins Kevin R. Collins, Director	March 16, 2011
/s/ Jerrie F. Eckelberger Jerrie F. Eckelberger, Director	March 16, 2011
/s/ Jean-Michel Fonck Jean-Michel Fonck, Director	March 16, 2011
/s/ Aleron H. Larson, Jr. Aleron H. Larson, Jr., Director	March 16, 2011
/s/ Russell S. Lewis Russell S. Lewis, Director	March 16, 2011
/s/ Anthony Mandekic Anthony Mandekic, Director	March 16, 2011
/s/ James J. Murren James J. Murren, Director	March 16, 2011
/s/ Jordan R. Smith Jordan R. Smith, Director	March 16, 2011
/s/ Daniel J. Taylor Daniel J. Taylor, Director	March 16, 2011
/s/ Carl E. Lakey Carl E. Lakey, Director	March 16, 2011

STOCK PERFORMANCE GRAPH

The performance graph shown below was prepared using data prepared by Capital IQ, a Standard & Poor's Business. As required by applicable rules of the SEC, the graph was prepared based upon the following assumptions:

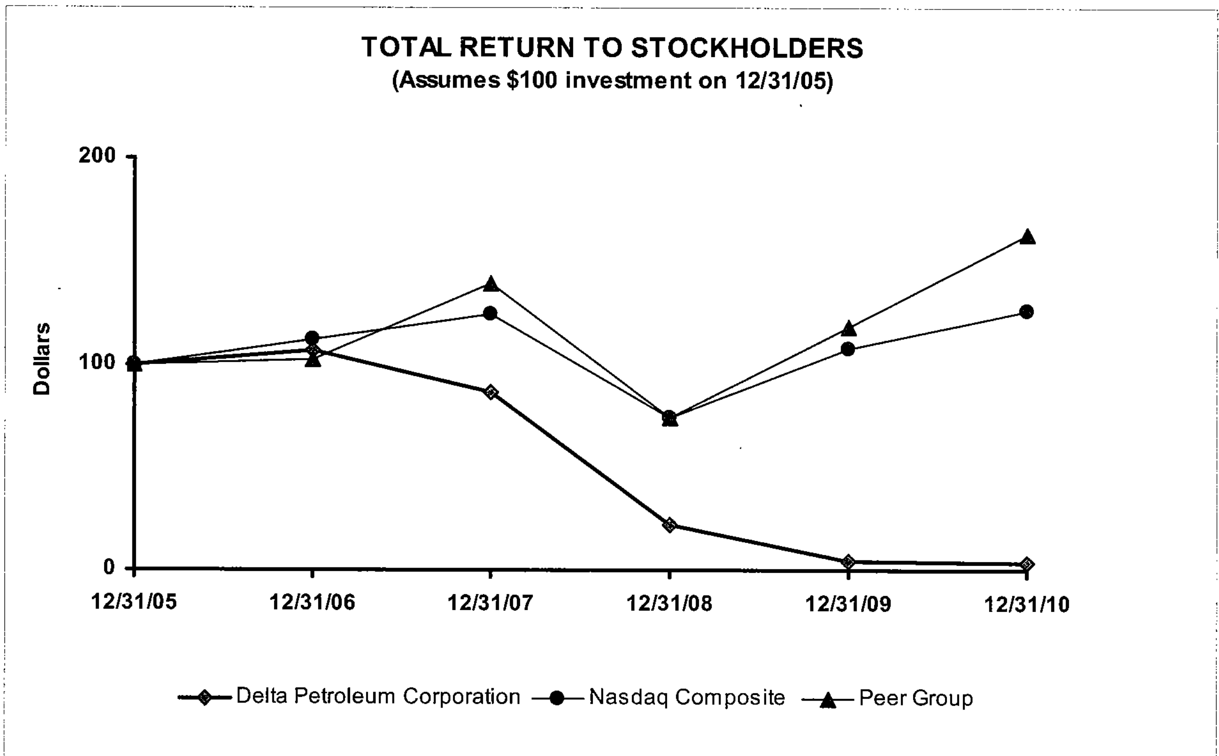
1. $100 was invested in Common Stock, the Nasdaq Composite Index (U.S.) and the Peer Group (as defined below) on December 31, 2005.

2. The Peer Group investment is weighted based on the market capitalization of each individual company within the Peer Group at the beginning of each period.

3. Dividends are reinvested on the ex-dividend dates.

The companies that comprise the Peer Group are: Brigham Exploration Co.; Cimarex Energy Co.; Forest Oil Corp.; Plains Exploration & Production Co.; Range Resources Corporation; SM Energy Co. and Whiting Petroleum Corp.

COMPARATIVE CUMULATIVE TOTAL RETURNS
DELTA PETROLEUM CORPORATION
NASDAQ COMPOSITE INDEX AND PEER GROUP
(Performance results through December 31, 2010)



Total Return Analysis						
	12/31/05	**12/31/06**	**12/31/07**	**12/31/08**	**12/31/09**	**12/31/10**
Delta Petroleum Corp.	$104.98	106.38	86.59	21.86	4.78	3.49
Peer Group	$99.83	111.74	124.67	73.77	107.12	125.93
Nasdaq Composite	$159.60	102.29	139.31	73.84	117.86	163.07

Officers and Directors

Carl E. Lakey
President, CEO and Director

Kevin K. Nanke
Treasurer and CFO

Stanley F. Freedman
EVP, General Counsel and Secretary

Outside Directors

Hank Brown #
Senior Counsel to Brownstein Hyatt Farber Schreck PC

Kevin R. Collins C*, #, x
CFO of Bear Tracker Energy

Jerrie F. Eckelberger *, C#, x
Attorney

Jean-Michel Fonck
President of Geopartners SAS

Aleron H. Larson, Jr.
Private Investor

Russell S. Lewis *, #, x
Executive Vice President of Strategic Development of VeriSign, Inc.

Anthony Mandekic #
Secretary/Treasurer of Tracinda Corporation

James J. Murren #, x
Chairman and CEO of MGM Mirage

Jordan R. Smith *, #,Cx
President of Ramshorn Investments, Inc.

Daniel J. Taylor CB, *, x
Executive of Tracinda Corporation

CB Chairman of the Board
*** Audit Committee**
 # Compensation Committee
x Nominating & Governance Committee
C Committee Chairman

Corporate Information

Common Stock Listing
Listed on NASDAQ as DPTR

Corporate Offices
Delta Petroleum Corporation
370 17th Street
Suite 4300
Denver, Colorado 80202
(303) 293-9133

Investor Relations Contacts
Broc Richardson
VP of Corporate Development and Investor Relations

Andrea Brown
Investor Relations Coordinator

Corporate Website
www.deltapetro.com

Independent Auditors
KPMG LLP
Denver, Colorado

Transfer Agent
Corporate Stock Transfer
3200 Cherry Creek Drive South
Suite 430
Denver, Colorado 80209
(303) 282-4800

Communications concerning the transfer of shares, lost certificates, duplicate mailings or change of address should be directed to the transfer agent.

Annual Meeting
The annual meeting of stockholders will be held at 10:00 a.m. MDT on July 12, 2011 at Delta's offices, 370 17th Street, Suite 4300, Denver, Colorado 80202.

Form 10-K
Copies of the Company's Annual Report on Form 10-K may be obtained, without charge, by contacting Investor Relations at (303) 293-9133 or investorrelations@deltapetro.com.

Forward-Looking Statements
Forward-looking statements in this report are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based on management's present expectations, estimates and projections, but involve risks and uncertainty, including without limitation, the availability of capital and the ability to grow reserves, production and cash flow. Please refer to the report on Form 10-K for the year ended December 31, 2010 and subsequent reports on Forms 10-Q and 8-K as filed with the Securities and Exchange Commission for additional information. The Company is under no obligation (and expressly disclaims any obligation) to update or alter its forward-looking statements, whether as a result of new information, future events or otherwise.

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CORPORATION

Delta Petroleum Corporation
370 17th Street, Suite 4300
Denver, Colorado 80202
(303) 293-9133

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