DELTA
PETROLEUM
CORPORATION

2009 ANNUAL REPORT

Dear Shareholders,

The 2009 fiscal year was a very challenging one for the economy in general and Delta Petroleum Corporation in particular. As a result of deteriorating economic conditions and depressed natural gas prices, we experienced a significant decrease in our revenues and operating cash flow resulting in a corrosion of our financial condition and liquidity. Accordingly, we turned our attention to capital and operational cost control in conjunction with a deleveraging strategy, which included the implementation of extensive staff reductions and other cost-cutting efforts, coupled with the completion of a common equity offering that raised approximately $248 million, the collection of approximately $103 million in net proceeds from the United States government during the year and the receipt of additional proceeds from non-core asset sales. These efforts enabled us to reduce our overall debt balance and improve our cash flow quarter over quarter throughout the year, despite a steady decline in production from the cessation of our drilling program.

While 2009 began with serious challenges, 2010 began with opportunities and increased optimism. We have sufficient liquidity to begin our drilling program and have reduced our overhead as well as our operating and capital cost structure. We look forward to restarting an active drilling program in developing our low-risk, repeatable drilling inventory in the Piceance Basin, which is our core asset and where we have previously demonstrated a track record of efficient production and reserve growth.

We have the assets and the team to once again execute on the strategy to provide a growth-oriented oil and gas company. We continue to be grateful for the support of our shareholders and we understand the responsibility we have to you. The management and employees of Delta remain steadfast in our commitment to deliver a company of which you can be proud.

Daniel J. Taylor
Chairman of the Board

John R. Wallace
President and Chief Operating Officer

Kevin K. Nanke
Chief Financial Officer and Treasurer

DELTA
PETROLEUM
CORPORATION

2009 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, 2009

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 Global Select 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, 2009, the aggregate market value of voting stock held by non-affiliates of the registrant was approximately $263.4 million, based on the closing price of the Common Stock on the NASDAQ National Market of $1.93 per share. As of February 28, 2010, 282,844,446 shares of registrant's Common Stock, $.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 2010 Annual Meeting of Stockholders.

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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 strategic plans; operating strategies; our expectation that we will have adequate cash from operations, credit facility borrowings and other capital sources to satisfy our obligations under the Second Amendment to our Second Amended and Restated Credit Agreement, and to meet future debt service, capital expenditure and working capital requirements; expected announcements of 2010 drilling plans and capital expenditure budget; anticipated utilization of joint venture and partnership structures; 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 the Second Amendment to our Second Amended and Restated Credit Agreement, 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 contraction in the demand for natural gas in the U.S. as a result of depressed general economic conditions;
- the ability and willingness of our joint venture partners to fund their obligations to pay a portion of our future drilling and completion costs;
- 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;
- the risk that lenders under our revolving credit facilities will default in funding borrowings as requested; 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 areas of operation are the Rocky Mountain and onshore Gulf Coast Regions, which together comprise the majority of our proved reserves, production and long-term growth prospects. 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.

We generally concentrate our exploration and development efforts in fields where we can apply our technical expertise, and where we have accumulated significant operational control and experience. We also have an ownership interest in a drilling company, providing the benefit of priority access to drilling rigs during high rig utilization periods.

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

Evaluation of Strategic Alternatives
In November 2009, we retained Morgan Stanley and Evercore Partners (collectively, "Strategic Advisors") to evaluate and advise the Board of Directors on strategic alternatives to enhance shareholder value and the process is currently in advanced stages. Such alternatives are expected to include, but may not be limited to, exploring the sale of some or all of our assets, entering into partnerships or joint ventures, or the sale of the entire company (collectively, the "Potential Strategic Transactions"). There can be no assurance that this evaluation of strategic alternatives will result in changes to our company, operations or business plan. In addition, there can be no assurance that we will pursue any particular transaction or transactions, or, if we do pursue any such transaction, that it will be completed or successful.

Amendment to Credit Facility
On October 30, 2009, we 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 our credit agreement in which, among other changes, the lenders provided waivers from the December 31, 2009 and March 31, 2010 current ratio and consolidated secured debt to EBITDAX ratio covenants. In conjunction with the Second Amendment and as part of a scheduled redetermination, the borrowing base under the Credit Agreement was reduced from $225.0 million to $185.0 million. The next scheduled borrowing base redetermination under the Credit Agreement is currently in process. Also, the Second Amendment requires that we maintain minimum availability of $20.0 million essentially reducing our availability under the Credit Agreement. The minimum availability requirement will be released on the first date after delivery of the December 31, 2009 audited financial statements on which we are in compliance with our financial covenants as of the most recently completed quarter (without giving effect to any waiver of compliance with such covenants) and project pro forma compliance for each of the four following quarters. In addition, the Second Amendment imposed capital expenditures limitations of $10.0 million for the quarter ending December 31, 2009, $10.0 million for the quarter ending March 31, 2010, and $5.0 million for the quarter ending June 30, 2010, provided that any excess of the limitation over the amount of actual expenditures may be carried forward from an earlier quarter to a subsequent quarter. The Second Amendment also included a payables covenant whereby our trade payables (a sub-component of accounts payable on the accompanying consolidated balance sheet) may not exceed $30.0 million, exclusive of any amounts owed by us to DHS Drilling Company ("DHS"), our drilling subsidiary. We are currently in compliance with our financial ratio covenants and based on our current operating projections, we believe that we will remain in compliance with the debt covenants. However, depending on market conditions and the possibility of further economic deterioration, we may need to request amendments, or waivers for the covenants, or obtain refinancing in future periods. There can be no assurance that we will be able to obtain amendments or waivers, or negotiate agreeable refinancing terms should it become needed.

Overview and Strategy

Although we have undertaken an evaluation of strategic alternatives, our corporate strategy remains focused on increasing stockholder value, as follows:

Pursue development of our core areas independently and through joint ventures or other industry partnerships

Although our capital expenditure budget was reduced dramatically in 2009 due to significant declines in commodity prices and our capital availability, and remains limited in 2010 by our capital availability and by the limitations imposed under the Second Amendment, our financial condition has improved and Rockies gas prices have recently begun to return to more attractive levels supporting additional development. We are unable to accurately predict our anticipated capital expenditures for fiscal year 2010, primarily due to the uncertainty relating to any Potential Strategic Transaction, including the likelihood of such a transaction occurring, the type of transaction and the timing of any such transaction. In addition, future redeterminations of our borrowing base under our credit facility, including the scheduled redetermination currently in process, may affect our liquidity available for capital expenditures making it difficult to accurately determine such amounts at the current time. We expect to announce our 2010 drilling plans once our strategic alternatives evaluation process and borrowing base redetermination are complete. It is our current belief that our 2010 capital deployment will be focused in the Rockies, which we believe will allow us to maintain approximately 90% of our 2009 production levels in 2010 until improved commodity prices and capital availability are able to support more aggressive drilling and completion activity.

In view of current market conditions and our capital expenditure constraints, we intend to more actively utilize joint ventures or other similar industry partnerships or participation arrangements to develop our asset base. In 2008, we announced the sale of 50% of our working interests in our Columbia River Basin acreage and are continuing to evaluate, among other alternatives, a joint venture or similar industry partnership transaction or transactions with the assistance of our Strategic Advisors. We are currently engaged in other joint venture focused discussions regarding development of several of our other unproved leasehold areas.

Achieve reserve growth through repeatable development

In 2009 we experienced a decrease in reserves due to the exclusion of our Piceance Basin proved undeveloped reserves given low Rockies gas prices over the course of the year as factored into the new SEC rules on pricing for year end reserve calculations. Prior to 2009, however, for a four-year period we experienced significant reserve growth through a combination of acquisitions and drilling successes. Although prior to 2006 the majority of our reserve and production growth came through acquisitions, in 2007 and 2008 we achieved reserve and production increases as a result of our drilling program. In 2009, we successfully focused on the efficient deployment of available capital to maintain production levels and experienced a decline of 11% in 2009 volumes relative to 2008. We anticipate that the majority of our future reserve and production growth will come through the execution of our development drilling program in our Piceance Basin projects, which contain a development drilling inventory generally consisting of locations in fields that demonstrate low variance in well performance, leading to predictable and repeatable field development.

Our reserve estimates change continuously and we evaluate such reserve estimates on a quarterly basis, with an independent engineering evaluation completed on an annual basis. Deviations in the market prices of both crude oil and natural gas and the effects of acquisitions, dispositions and exploratory development activities have a significant effect on the quantity and present and future values of our reserves.

Maintain high percentage ownership and operational control over our asset base

As of December 31, 2009, we controlled approximately 797,000 net undeveloped acres, representing approximately 98% of our total net acreage position. We retain a high degree of operational control over our asset base, as we generally have a high average working interest or act as the operator in our areas of significant activity. This provides us with controlling interests in a multi-year inventory of drilling locations, positioning us for reserve and production growth through our drilling operations when we are able to increase our drilling activity. This level of ownership and control also enables us to seek joint ventures or industry partnerships on the acreage. We plan to maintain this advantage to allow us to control the timing, level and allocation of our drilling capital expenditures and the technology and methods utilized in the planning, drilling and completion process, though our ability to control these matters may be diminished by the terms of joint venture or partnership arrangements we may enter into. We believe this flexibility to opportunistically pursue exploration and development projects relating to our properties is particularly valuable in view of the current lower commodity price and limited capital availability environment. We also have a 49.8% interest in DHS, as well as a contractual right of priority access to 18 drilling rigs owned by DHS.

Maintain and/or monetize acreage positions in high potential resource plays

We anticipate that like 2009 our exploratory drilling efforts during 2010 will be much more limited than in prior years. Although, we believe that our ongoing development of reserves in our core areas should be supplemented with exploratory efforts that may lead to new discoveries in the future, we will devote the vast majority of our capital resources to development of our existing core areas and seek carried, farmout or joint venture arrangements in pursuing exploratory opportunities. We continually evaluate our opportunities and pursue attractive potential opportunities that take advantage of our strengths. We have significant undeveloped, unproved acreage positions in the Columbia River Basin of Washington and Oregon, the Haynesville and Eagleford shales in Texas, and the Central Utah Hingeline, each of which has gained substantial interest within the exploration and production sector due to their relatively unexplored nature and the potential for meaningful hydrocarbon recoveries. There are other mid-size and large independent exploration and production companies conducting drilling activities in these plays. With increased commodity prices or the addition of joint venture partners to fund a portion or all of the drilling cost, our plans for 2010 could change with respect to these potentially rewarding exploratory plays.

Pursue a disciplined acquisition and disposition strategy

Historically we have been successful at growing through targeted acquisitions. Although our multi-year drilling inventory provides us with the opportunity to grow reserves and production organically without acquisitions, we continue to evaluate acquisition opportunities, primarily in our core areas of operation. In addition, as we did in the latter half of 2009 in particular, we will continue to look to divest of assets located in fully developed or non-core areas.

Maintain an active hedging program

We manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives. 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 limit the risk of fluctuating cash flows used to fund our capital expenditure program. We also typically use hedges in conjunction with acquisitions to achieve expected economic returns during the payout period. During March 2009, we entered into derivative contracts that originally established a commodity floor price for our anticipated production of 40% for the last two quarters of 2009, 70% for the calendar year 2010 and 50% for the calendar year 2011. Depending upon the outcome of our assessment of Potential Strategic Transactions, we would expect to further evaluate our commodity price risks for the next 12 to 36 month period and periodically enter into derivative contracts to manage such risks.

Experienced management and operational team

Our senior management team has, on average, over 25 years of experience in the oil and gas industry, and has a proven track record of creating value both organically and through strategic acquisitions. Our management team is supported by an active board of directors with extensive experience in the oil and gas industry. Our experienced technical staff utilizes sophisticated geologic and 3-D seismic models to enhance predictability and reproducibility over significantly larger areas than historically possible. We also utilize multi-zone, multi-stage artificial stimulation ("frac") technology in completing our wells to substantially increase near-term production, resulting in faster payback periods and higher rates of return and present values. Our team has successfully applied these techniques in the completions of our wells in our Rocky Mountain natural gas fields.

Operations

During the year ended December 31, 2009, 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, 2009:

	Oil (Mbbl)	Natural Gas (Mmcf)	Total (Mmcfe)	2009 Production (MMcfe/d) [1]
Proved Developed				
Rocky Mountain Region	927	100,104	105,666	43.3
Gulf Coast Region	1,838	14,792	25,820	14.8
Other	212	108	1,380	2.6
Total	2,977	115,004	132,866	60.7
Proved Undeveloped				
Rocky Mountain Region	428	3,346	5,914	
Gulf Coast Region	1,043	8,342	14,601	
Other	34	-	204	
Total	1,505	11,688	20,719	
Total Proved Reserves[2]	4,482	126,692	153,585	

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

(2) Based on historical first of month twelve month average spot prices of $61.18 per Bbl for WTI oil and $3.03 per MMBtu for CIG natural gas, in each case adjusted for differentials, contractual deducts and similar factors.

In December 2008, the SEC approved new rules designed to modernize oil and gas reserve reporting requirements.

We adopted the rules effective December 31, 2009. The application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have been used under the previous rules. Use of new 12-month average pricing rules at December 31, 2009 resulted in a decrease in proved reserves of approximately 677 Bcfe as compared to proved reserves calculated using the year-end prices previously required. See "Reserve Sensitivities" included in Item 7. Management's Discussion and Analysis.

We intend to focus our 2010 capital spending on the development of our core area of operation in the Rocky Mountains, the Piceance Basin, to the extent that cash on hand, cash flows and available capital through joint ventures or asset sales are adequate to fund our plans. The Second Amendment to our Credit Agreement limits our ability to make capital expenditures during the first and second quarters of 2010.

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, CRB Partners, LLC ("CRBP") and PGR Partners, LLC ("PGR"), we currently own producing and non-producing oil and natural gas interests, undeveloped leasehold interests and related assets in nine 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 majority of our properties and 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, an affiliated Colorado corporation 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, 2009, DHS owned 18 drilling rigs with depth ratings of approximately 10,000 to 25,000 feet, of which seven are currently active. We have the right to use all of the rigs on a priority basis, although current economic conditions have resulted in an abundance of available drilling rigs in the Rocky Mountain area at the present time.

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

	Years Ended December 31,	
	2009	2008
Average number of rigs owned during period	18.5	16.7
Total rig days[1]	854	5,032
Average drilling revenue per day	$ 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 (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, we expect drilling day rates to stabilize during 2010.

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.

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, although DHS currently has one rig operating in Mexico. 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 is permitted 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 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, 2009, we had two companies that individually accounted for 37% and 19% 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 19 to our consolidated financial statements for additional information.

During the year ended December 2009, DHS had two companies that individually accounted for 24% and 10% 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 2010. 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 2010, 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 petroleum from cleanup liability, many state laws affecting our operations impose clean-up liability regarding petroleum and petroleum-related products.

In addition, although RCRA currently classifies certain exploration and production wastes as "non-hazardous," 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.

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, Mineral Management Service ("MMS"), which currently impose 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 Department of the Interior 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 MMS 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 $10.5 million at December 31, 2009. 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, 2009 we had approximately 79 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. Current economic fundamentals portray an uncertain outlook for the oil and natural gas exploration and development business for at least a significant portion of 2010 due to volatile oil and natural gas prices coupled with the global recession. 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. Our ability to maintain adequate liquidity through 2010 will depend significantly on consummation of a Potential Strategic Transaction and, if so, the terms thereof, sustained commodity price improvement, adequate pipeline capacity, curtailment of operating expenses and 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 or capital markets conditions will improve in the near term.

Consummation of a strategic transaction, sale of assets, or joint venture or partnership arrangement may be necessary to fund our capital expenditure and working capital needs in the near term.

In 2009, we successfully completed a public offering of our common stock in exchange for $246.9 million of net proceeds, as well as received net proceeds of $95.7 million from the settlement of litigation in which we were involved. In 2009, we also experienced reductions in our borrowing base and our borrowing availability under our Credit Agreement, as well as a decline in revenues due to general economic conditions and commodity prices. Accordingly, the proceeds from our capital-raising activities in 2009 were used for the repayment of debt as well as capital expenditures and general working capital. Although we have significantly decreased our drilling activities and operations in recent periods, any further reductions could materially and adversely affect our continuing operations. Thus, in response to these liquidity issues, in November 2009, we announced that we were exploring strategic alternatives, including a sale of some or all of our assets, entering into partnerships or joint ventures, or the sale of the entire company. Based on the current status of our balance sheet, the consummation of one or more of these types of transactions may be required to fund our drilling activities and operations in 2010 if adequate capital is not obtained from another source. Further, our borrowings under our Credit Agreement are currently due on January 15, 2011. If we are unable to complete any Potential Strategic Transaction, we may not be able to repay the amounts outstanding under the credit facility when due without obtaining other sources of capital from 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.

As of December 31, 2009, our total outstanding long term liabilities were $460.9 million, including $83.3 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 39.8% of our total book capitalization at December 31, 2009. Based on the revised $185.0 million borrowing base with a required availability cushion of $20.0 million and outstanding letters of credit totaling $1.2 million, we had $39.8 million available under our credit facility as of December 31, 2009 and $70.8 million as of February 28, 2010. 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 that are important to our growth; 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, develop our properties and make future acquisitions. 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, including a scheduled borrowing base redetermination currently in process. A further 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 existing credit facility matures on January 15, 2011 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 lenders, or entering into a new credit facility. As part of our consideration of Potential Strategic Transactions, 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.

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 from the lending banks in our credit facility is subject to periodic redeterminations based on prices specified by our bank group at the time of redetermination. In addition, we may have asset carrying value write-downs if prices fall, as was the case in 2009.

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 82% of our reserves at December 31, 2009 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 2010 will most likely allow us to fund our business with anticipated internally generated cash flow, cash resources and other 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, 2009, 2008 and 2007 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 and 2007, in accordance with SEC rules at the time, proved reserves were based on single day year-end prices. For 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.

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, 2009, we recorded impairment provisions to our proved and unproved properties totaling approximately $155.5 million primarily related to our non-operated Garden Gulch field in the Piceance Basin ($38.6 million), Haynesville Shale ($27.5 million), Columbia River Basin ($21.4 million), Lighthouse Bayou ($14.8 million), proved and unproved impairments in various Gulf Coast fields ($29.2 million), Vega surface land ($10.5 million), proved and unproved impairments in various Rockies fields ($6.9 million), and pipe and tubular inventory ($4.3 million). 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 to our proved and unproved properties totaling approximately $305.6 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas ($192.5 million), Paradox field in Utah ($30.5 million), Howard Ranch and Bull Canyon fields in the Rockies ($32.0 million), Utah Hingeline ($40.8 million) and our offshore California field ($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 ($21.5 million), certain DHS rigs ($21.6 million) and we wrote off DHS's goodwill ($7.7 million).

We incurred dry hole costs of approximately $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.

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

Our Credit Agreement 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 revolving bank 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 borrowing base has been redetermined at a level that will not permit additional borrowing 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. Pursuant to the Second Amendment to the Credit Facility, our borrowing base under the Credit Facility was reduced to $185.0 million, with a requirement that we maintain minimum availability of $20.0 million.

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, 2009 is estimated to be approximately $78.0 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 depend on key personnel.

We currently have four employees that serve in executive management roles. In particular, John R. Wallace, our President, and Carl Lakey, our Senior Vice President - Operations are responsible for the operation of our oil and gas business, 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 seven of its 18 rigs in operation and expects to continue to incur liquidity pressures during 2010 due to the industry-wide decrease in drilling activities. DHS is now highly leveraged relative to its currently reduced cash flow and its 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, 2009, DHS owed $83.3 million under its credit facility. 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 in 2010 unless market conditions improve significantly. In such event, 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. While the DHS credit facility is non-recourse to Delta, Delta is a significant creditor of DHS, with accounts payable to DHS of $20.5 million as of December 31, 2009. Delta has a net investment of approximately $8.5 million in DHS.

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 costless collars. 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 ($28.1 million), $21.7 million, and $10.0 million for the years ended December 31, 2009, 2008 and 2007, respectively. At December 31, 2009, we had derivative contracts in place that originally established a floor price for our anticipated production of 40% for the last two quarters of 2009, 70% for the calendar year 2010 and 50% for the calendar year 2011.

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 continue to 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.

We may be unable to draw funds from our existing credit facilities.

Our subsidiary, DHS Drilling Company, has a credit facility with Lehman Commercial Paper, Inc. ("Lehman"). During the year ended December 31, 2008, DHS paid a deposit of $1.3 million for the acquisition of a drilling rig that was expected to close in October 2008. Because of the bankruptcy of Lehman and the inability of Lehman to fund, DHS was unable to close on the acquisition and forfeited its deposit. We maintain a Credit Facility underwritten by a syndicate of financial institutions that we use to fund our capital expenditures and working capital requirements. If the financial institutions underwriting our credit facility file for bankruptcy or otherwise refuse our funding requests, we may incur unforeseen expenses, lose business opportunities, or become unable to make payments when due.

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.

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, 2010, our largest stockholder, Tracinda Corporation ("Tracinda"), beneficially owned 93,798,000 shares of our common stock, or approximately 34% of the outstanding shares of our common stock. Pursuant to the Company Stock Purchase Agreement that we entered into with Tracinda Corporation on December 29, 2007, Tracinda Corporation 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. While Tracinda Corporation agreed not to acquire more than 49% of our outstanding common stock until February 20, 2009, after such date there are 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.

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.

Approximately 40% of our common stock is held by institutional investors who now each have ownership of greater than 5% of our common stock. Sales by Tracinda Corporation, or other of our large institutional investors, 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 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 employees of the Company, holders of our common stock will experience dilution. As of December 31, 2009, we had outstanding options to purchase 1,427,750 shares of common stock at a weighted average exercise price of $8.21. 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, 2009, our directors and executive officers collectively and beneficially owned, directly or indirectly, approximately 1.3% 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.

Our primary areas of activity are in the Rocky Mountain and Gulf Coast Regions with additional unproved exploratory leaseholds in the Columbia River Basin in southeastern Washington, the Hingeline area of Central Utah, and the Haynesville Shale area of Texas, among others. Total oil and gas leasehold is approximately 813,000 acres.

Rocky Mountain Region

The Rocky Mountain Region comprises approximately 73% of our estimated proved reserves as of December 31, 2009. The majority of our undeveloped acreage and drilling inventory is located in this region, where our drilling efforts and capital expenditures have been focused.

In the Rocky Mountains, although we have significant acreage in three basins, we have dedicated the majority of our development efforts to our position in the Piceance Basin.

Piceance Basin. 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. In 2008 we acquired an additional 17,300 net acres, which increased our position to approximately 22,150 net acres, which has over 2,000 net drilling locations on 10-acre spacing. We also have a non-operated working interest in the Garden Gulch Field in Garfield County, Colorado. These fields are consistent with our strategy of targeting reservoirs that demonstrate predictable geology over large areas. The Williams Fork member of the Mesaverde formation is the primary producing interval and has been successfully developed throughout the Piceance Basin.

Vega Area. The Vega Area includes the Vega Unit, the North Vega leasehold, the Buzzard Creek Unit, and North Buzzard Creek leasehold. Our working interest in the Vega Area varies between 95-100%. During fiscal 2008, we increased proved reserves in the Vega Area over 295% to 719.9 Bcfe and increased production from approximately 25 Mmcf/d at the beginning of the year to approximately 48 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, proved reserves decreased to 84.7 Bcfe. Production decreased to 25.8 Mmcf/d at the end of 2009 due to the limited capital spending during 2009. The Collbran Valley natural gas pipeline provides us with approximately 100 Mmcf/d of pipeline takeaway capacity. The pipeline system is expandable to 290 MMcfd with additional compression at CVGG Anderson Gulch Facility. We ended 2009 with 188 wells producing. Despite our large inventory of over 2,000 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, 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 expect to continue completion activities in 2010 on wells awaiting completion, and to resume an active, continuous drilling program once commodity prices recover. Our drilling and completion capital budget for the Vega Area has not yet been determined pending the outcome of our borrowing base redetermination and the outcome of the previously discussed strategic alternatives process.

Garden Gulch. We have an interest in approximately 6,300 gross (2,000 net) acres with a 31.1% non-operated working interest. The operator of the project temporarily ceased drilling activity in 2009, but resumed completion activity in late 2009 and began a one rig drilling program in early 2010. Our capital budget for the year ending December 31, 2010 is driven by the activity level, which is determined by the operator.

Paradox Basin. In the Paradox Basin we have five prospect areas: Greentown, Salt Valley, Fisher Valley, Gypsum Valley and Cocklebur Draw. Over the past three years we focused primarily on the Greentown prospect, in Grand County, Utah. The objectives that were targeted in these prospects were reliant upon various geologic models, which included multiple stacked clastic intervals imbedded within an evaporate salt in the Paradox formation, and unconventional shales.

Greentown. From 2006 through 2008, we drilled a total of eight wells in the Greentown project area. Delta observed encouraging hydrocarbon flows from three of the initial wells. The Greentown 36-11, 32-42 and 28-11 which all produced hydrocarbon from one or more of the clastic intervals at commercial rates. Although these first two exploration wells were lost due to casing failure, subsequent wells were drilled with improved casing designs and did not experience similar failure. Due to Delta's need to devote its limited capital to the Piceance Basin properties in 2010, we have farmed out our interest in several of the Paradox wellbores to another firm and retained a carried 25% interest in the completion of each of the wellbores. The farmout specifically assigns operating rights to the Federal 28-11 and Greentown Federal 26-43D well along with associated abandonment responsibilities. The agreement also provides for the option to extend the agreement to other wellbores.

We have a 70% working interest in 34,000 gross acres, 23,400 net acres. The acreage remains prospective and we are hopeful that the farmout will prove successful. We have not budgeted any significant activity in Greentown for the year ending December 31, 2010.

Salt Valley. The Salt Valley project area has had one exploratory well drilled. Additional drilling plans are not expected in 2010. We have a 70% working interest in 7,065 gross acres, 4,900 net acres.

Fisher Valley, Gypsum Valley and Cocklebur Draw. We have three remaining prospects in the Paradox Basin located in San Miguel and Dolores Counties, Colorado and Grand County, Utah. We have a 70% working interest in 49,200 gross acres, 36,600 net acres, all of which were undeveloped at December 31, 2009.

Denver-Julesburg ("D-J") Basin. Our leasehold in the Denver Julesburg Basin focuses on the "J" sand formation at depths of between 7,000 feet and 8,000 feet. In 2007 we drilled an exploratory well, the Cowboy 35-21 well, which was a discovery that began production at a rate of 200 Bo/d. Subsequent development of the Cowboy field included ten additional wells which allowed production to peak at approximately 1,100 barrels of oil per day. Production has since declined to 330 Bopd. We have identified numerous seismically defined structures, similar in size to the Cowboy field. We have 70,243 net acres with a 100% working interest. Our drilling capital expected for the D-J Basin in 2010 is primarily related to a well which spud in late January 2010 and is expected to be on production by the end of April 2010.

Gulf Coast Region

The Gulf Coast Region comprises approximately 26% of our estimated proved reserves as of December 31, 2009. In the Gulf Coast Region, our primary areas of operation are the Newton and Midway Loop Fields.

Development Projects — Newton, Midway Loop and Opossum Hollow Fields

Newton Field. The Newton Field is located in Newton County, Texas where we have an interest in 4,874 net acres with a 92% working interest. The wells in the Newton Field produce from 13 different sands in the Wilcox formation. The field is a large structural anticline that is defined by extensive well and seismic control. At year end, proved reserves in the Newton Field were 16.2 Bcfe. We do not currently anticipate allocating any significant drilling capital for the Newton Field in 2010.

Midway Loop Field. The Midway Loop Field is located in Polk and Tyler Counties, Texas. We have an interest in 12,674 gross acres, with an average 39% working interest. The wells in this field produce from the Austin Chalk and are drilled horizontally with either dual or single laterals that reach up to 8,000 feet of displaced in each lateral. As of December 31, 2009 our proved reserves totaled 12.2 Bcfe. Currently, there is no drilling capital anticipated for the field in 2010.

Caballos Creek / Opossum Hollow / 74 Ranch Areas. The leasehold is located in Atascosa and McMullen Counties, Texas. We have an interest in approximately 9,722 gross acres. The area has additional potential in the Wilcox sands, Eagleford shales, Sligo formation and Cotton Valley sands that are supported by acquired 3-D seismic programs. Delta is participating for 25% carried interest in a well currently drilling near the 74 Ranch area. We are currently evaluating additional farmout options in the 74 Ranch area.

Other Areas

Central Utah Hingeline. The central Utah Hingeline Region is an overthrust belt located in central Utah. We have an average 65% working interest in approximately 125,000 net acres. We have drilled three wells, the Joseph #1, the Federal 23-44, and the Beaver Federal 21-14. All three wells were plugged and abandoned as dry holes.

We and our partners control approximately 210,000 gross acres (125,000 net acres) within this play and numerous structural features have been identified on our leasehold. We have not budgeted any drilling capital for this area in 2010. The Central Utah Hingeline project is an exploratory area for us and does not account for any of our proved reserves at December 31, 2009.

Columbia River Basin. The Columbia River Basin is located in southeast Washington and northeast Oregon. The basin is characterized by over-pressured, gas sandstone formations. During 2009, we drilled the Gray 31-23 well in Klickitat County, Washington however the well did not reach the targeted Roslyn formation and was plugged and abandoned. We have an interest in approximately 420,000 net acres in the basin, all of which are undeveloped. The Columbia River Basin is an exploration project area and does not account for any of our proved reserves as of December 31, 2009 and we do not anticipate any drilling capital for this area in 2010.

Haynesville Shale. We acquired rights to 11,900 gross acres in the Haynesville Shale during the second and third quarters of 2008. The acreage position is concentrated in Caddo Parish, Louisiana, and Harrison, Shelby and Nacogdoches counties, Texas. The costs to acquire the leasehold rights have averaged approximately $3,500 per acre. We are in the process of seeking a joint venture partner to begin drilling our leasehold. No 2010 capital is expected to be allocated to this acreage.

Offshore California producing properties

Point Arguello Unit. 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) with approximately 1.0 Bcfe in proved reserves. No capital expenditures are anticipated for this area for 2010.

Rocky Point Unit. We own a 6.25% working interest in the development of the east half of OCS Block 451 in the Rocky Point Unit.

Unproved Undeveloped Offshore California Properties

We previously owned direct and indirect ownership interests ranging from 2.49% to 100% in five unproved undeveloped offshore California oil and gas properties. We and our 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 our offshore California properties. During 2009, we received net proceeds of $95.8 million after contractual royalty obligations to third parties and conveyed our leases back to the United States. Accordingly, we no longer have any remaining unproved undeveloped offshore California property interests.

Other Fields

We derive a small portion of our oil and gas production from fields in non-core regions that are not expected to constitute a significant portion of our capital budget in the future. Our interest in these fields had approximately 0.6 Bcfe in proved reserves as of December 31, 2009. We divested of many of these fields in late 2009 generating net proceeds of $3.7 million.

Reserve Sensitivities

In December 2008, the SEC approved new rules designed to modernize oil and gas reserve reporting requirements. We adopted the rules effective December 31, 2009. The application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have been used under the previous rules. The table below compares our December 31, 2009 SEC reserves under the new rules with the December 31, 2009 proved reserves that would have been used from the use of the old rules:

	SEC Pricing (1) (Mmcfe)	Old SEC Pricing (2) (Mmcfe)
Proved developed	132,866	165,420
Proved undeveloped	20,719	664,885
Total Proved	153,585	830,305

(1) Based on historical first of month twelve month average spot prices of $61.18 per Bbl for WTI oil and $3.03 per MMBtu for CIG natural gas, in each case adjusted for differentials, contractual deducts and similar factors.
(2) Based on single day year-end prices of $79.36 per Bbl for WTI oil and $5.54 per Mmbtu for CIG natural gas, adjusted as described in (1) above.

As shown above, use of new 12-month average pricing rules at December 31, 2009 resulted in a decrease in proved reserves of approximately 677 Bcfe as compared to proved reserves calculated using the year-end prices previously required.

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 Sr. Vice President of Corporate Engineering. 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 2009, 2008 and 2007, 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, 2009 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, 2009 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

The Company owns 49.8% of DHS, which as of December 31, 2009 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	UT	2005	1,500	18,000
Rig No. 4	WY	2007	700	11,000
Rig No. 5	NV	2005	700	12,000
Rig No. 6	CO	2005	700	12,000
Rig No. 8	WY	2005	800	12,500
Rig No. 9	TX	2006	1,000	15,000
Rig No. 10	ND	2006	1,000	15,000
Rig No. 11	UT	2006	750	11,000
Rig No. 12	ND	2006	1,000	15,000
Rig No. 14	Mexico	2006	800	12,500
Rig No. 15	CO	2006	700	10,000
Rig No. 16	WY	2006	700	10,000
Rig No. 17	WY	2006	1,000	12,500
Rig No. 18	UT	2007	700	10,500
Rig No. 19	WY	2008	700	12,500
Rig No. 20	WY	2008	1,000	12,500
Rig No. 23	TX	2008	2,000	25,000
Rig No. 24	NM	2008	1,300	12,500

Office Facilities

Our offices are located at 370 Seventeenth Street, Suite 4300, Denver, Colorado 80202. We lease approximately 32,000 square feet of office space. Our current lease payments are approximately $97,200 per month and our lease expires in December 2014.

Production

During the years ended December 31, 2009, 2008 and 2007, 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, 2009, we recorded impairment provisions to our proved and unproved properties totaling approximately $155.5 million primarily related to our non-operated Garden Gulch field in the Piceance Basin ($38.6 million), Haynesville Shale ($27.5 million), Columbia River Basin ($21.4

million), Lighthouse Bayou ($14.8 million), proved and unproved impairments in various Gulf Coast fields ($29.2 million), Vega surface land ($10.5 million), proved and unproved impairments in various Rockies fields ($6.9 million), pipe and tubular inventory ($4.3 million), and Paradox pipeline ($1.9 million).

In 2008, we recorded an impairment provision to our proved and unproved properties totaling approximately $305.6 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas ($192.5 million), Paradox field in Utah ($30.5 million), Howard Ranch and Bull Canyon fields in the Rockies ($32.0 million), Hingeline field in Utah ($40.8 million) and our offshore California field ($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 ($21.5 million), certain DHS rigs ($21.6 million) and we wrote off DHS goodwill ($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, 2009, 2008, and 2007.

	Years Ended December 31,		
	2009	2008	2007
Production volume –			
Total production (MMcfe)	22,156	24,908	17,763
Production from continuing operations:			
Oil (MBbls)	761	993	1,003
Natural Gas (MMcf)	17,590	18,948	10,866
Total (MMcfe)	22,156	24,908	16,882
Net average daily production-continuing operations:			
Oil (Bbl)	2,085	2,721	2,748
Natural Gas (Mcf)	48,192	51,912	29,770
Average sales price:			
Oil (per barrel)	$ 52.37	$ 92.12	$ 67.39
Natural Gas (per Mcf)	$ 3.13	$ 6.87	$ 5.17
Hedge gain (loss) (per Mcfe)	$ (.05)	$ .74	$ .82
Lease operating costs - (per Mcfe)	$ 1.41	$ 1.35	$ 1.24

Productive Wells and Acreage

The table below shows, as of December 31, 2009, 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		Developed Acres	
Location	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
California (onshore)	-	-	-	-	1,014	55
California (offshore)	34	2.1	-	-	2,422	269
Colorado	347	1.8	390	215.5	2,920	2,100
Kansas	2	-	-	-	-	-
Louisiana	43	2.0	-	-	773	501
Mississippi	2	-	-	-	-	-
Nebraska	3	1.2	-	-	120	48
New Mexico	2	-	2	.1	241	14
Oklahoma	-	-	-	-	560	110
Texas (4)	316	51.7	54	12.6	20,117	10,868
Utah	-	-	-	-	80	61
Wyoming	14	12.3	20	14.7	1,768	1,587
	763	71.1	466	242.9	30,015	15,613

(1) All of the wells classified as "oil" wells also produce various amounts of natural gas.

(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.

(4) This does not include varying very small interests in approximately 666 gross wells (5.2 net) located primarily in Texas which are owned by our subsidiary, Piper Petroleum Company.

Undeveloped Acreage

At December 31, 2009, we held undeveloped acreage by state as set forth below:

	Undeveloped Acres (1)	
Location	Gross	Net
Colorado	100,848	77,899
Kansas	160	160
Louisiana	2,954	2,580
Nebraska	3,240	968
Oregon	393,948	45,160
Texas	23,171	18,165
Utah	287,979	183,353
Washington	1,245,634	375,900
Wyoming	133,424	92,959
Total	2,191,358	797,144

(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.

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,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells [1]:						
Productive:						
Oil	-	-	1	1.00	5	4.75
Gas	-	-	1	.70	4	3.09
Nonproductive	1	.50	19	14.01	5	4.16
Total	**1**	**.50**	**21**	**15.71**	**14**	**12.00**
Development Wells [1]:						
Productive:						
Oil	-	-	7	5.40	10	9.55
Gas	113	32.89	141	82.37	89	58.48
Nonproductive	-	-	-	-	2	1.13
Total	**113**	**32.89**	**148**	**87.77**	**101**	**69.16**
Total Wells [1]:						
Productive:						
Oil	-	-	8	6.40	15	14.30
Gas	113	32.89	142	83.07	93	61.57
Nonproductive	1	.50	19	14.01	7	5.29
Total Wells	**114**	**33.39**	**169**	**103.48**	**115**	**81.16**

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

Present Drilling Activity

We are unable to accurately predict our anticipated capital expenditures for fiscal year 2010, primarily due to the uncertainty relating to any Potential Strategic Transaction, including the likelihood of such a transaction occurring, the type of transaction and the timing of any such transaction. In addition, future redeterminations of our borrowing base under our credit facility, including the scheduled redetermination currently in process, may affect our liquidity available for capital expenditures making it difficult to accurately determine such amounts at the current time. We expect to announce our 2010 drilling plans once our strategic alternatives evaluation process and borrowing base redetermination are complete.

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.

The following legal proceedings have been recently terminated:

On December 16, 2009 we entered into a settlement agreement with the United States of America with respect to our 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 9 (the "Lease 452 Case"). On February 25, 2009, the Court of Federal Claims entered a judgment in our favor in the amount of $91.4 million with respect to our 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 we received gross proceeds of $65.0 million, which resulted in net proceeds to us of approximately $48.7 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.

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 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.

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

The following matters were submitted to a vote of security holders at a special meeting of stockholders held on December 22, 2009:

- An amendment to our Certificate of Incorporation to increase the number of authorized shares of our Common Stock from 300,000,000 to 600,000,000 was approved, with 191,566,899 shares voting in favor, 29,120,833 shares voting against and 1,03,957 shares abstaining.

- Our 2009 Performance and Equity Incentive Plan was approved with 125,933,694 shares voting in favor, 19,146,064 shares voting against and 359,865 shares abstaining.

No other matters were submitted to a vote of security holders during the fourth quarter of 2009.

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
John R. Wallace	50	President, Chief Operating Officer and a Director	October 2003 to Present
Kevin K. Nanke	45	Treasurer and Chief Financial Officer	December 1999 to Present
Stanley F. Freedman	61	Executive Vice President, General Counsel and Secretary	January 2006 to Present
Hank Brown	70	Director	June 2007 to Present
Kevin R. Collins	53	Director	March 2005 to Present
Jerrie F. Eckelberger	65	Director	September 1996 to Present
Jean-Michel Fonck	68	Director	May 2009 to Present
Aleron H. Larson, Jr.	64	Director	May 1987 to Present
Russell S. Lewis	55	Director	June 2002 to Present
Anthony Mandekic	68	Director	May 2009 to Present
James J. Murren	48	Director	February 2008 to Present
Jordan R. Smith	75	Director	October 2004 to Present
Daniel J. Taylor	53	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.

John R. Wallace, President and Chief Operating Officer, joined Delta in October 2003 as Executive Vice President of Operations and was appointed President in February 2006 and a Director in June 2007. Since April 1, 2005, he has also served as Executive Vice President and Director of DHS. Mr. Wallace was Vice President of Exploration and Acquisitions for United States Exploration, Inc. ("UXP"), a Denver-based publicly-held oil and gas exploration company, from May 1998 to October 2003. Prior to UXP, Mr. Wallace served as president of various privately held oil and gas companies engaged in producing property acquisitions and exploration ventures. He received a Bachelor of Science degree in Geology from Montana State University in 1981. He is a member of the American Association of Petroleum Geologists and the Independent Petroleum Association of the Mountain States.

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.

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 Chief Financial Officer of Bear Tracker Energy, a position he has held since December 2009. 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 2001. 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 Mirage 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 Mirage. He is also a member of the Board of Directors and the Executive Committee. Mr. Murren previously served in the following capacities for MGM Mirage: President (1999-2008), Chief Operating Officer (2007-2008), Chief Financial Officer (1998-2007), and Treasurer (2001-2007). Prior to his employment at MGM Mirage, 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.

Daniel J. Taylor has been an executive of Tracinda Corporation since February 2006 and has served as a Director of MGM Mirage 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 2006. 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.

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 our next annual meeting of 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 Global 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, 2008	$ 25.19	$ 17.80
June 30, 2008	28.37	21.50
September 30, 2008	26.19	12.35
December 31, 2008	13.75	3.75
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

On March 11, 2010, the closing price of our common stock was $1.42. 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 February 24, 2010 was approximately 1,450 which does not include an estimated 34,000 additional holders whose stock is held in "street name."

Recent Sales of Unregistered Securities

During the year ended December 31, 2009, 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

We did not repurchase any of our shares of common stock during the quarter ended December 31, 2009.

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, 2009	2008	2007	2006	Six Months Ended December 31, 2005	Year Ended June 30, 2005
	(In thousands, except per share amounts)					
Total Revenues	$ 182,442	$ 271,178	$ 194,941	$ 177,465	$ 48,715	$ 56,612
Loss from continuing operations	$ (349,684)	$ (468,268)	$ (148,962)	$ (12,033)	$ (27,205)	$ (11,370)
Net Income attributable to Delta common stockholders	$ (328,783)	$ (456,064)	$ (149,807)	$ 2,916	$ 219	$ 15,050
Income/(Loss) attributable to Delta common stockholders Per Common Share						
Basic	$ (1.56)	$ (4.77)	$ (2.44)	$ .06	$ -	$ .37
Diluted	$ (1.56)	$ (4.77)	$ (2.44)	$ .05	$ -	$ .36
Total Assets	$ 1,457,485	$ 1,894,963	$ 1,110,054	$ 932,614	$ 694,203	$ 512,983
Total Long-Term debt, including current portion	$ 460,923	$ 637,473	$ 393,468	$ 367,263	$ 248,733	$ 219,478
Total Delta Stockholders' Equity	$ 688,582	$ 762,390	$ 532,855	$ 431,523	$ 321,264	$ 221,623
Total Non-Controlling Interest	$ 8,538	$ 29,104	$ 27,296	$ 27,390	$ 15,496	$ 14,614
Total Equity	$ 697,120	$ 791,494	$ 560,151	$ 458,913	$ 336,760	$ 236,237

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 areas of operation are the Rocky Mountain and Gulf Coast Regions, which comprise 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, 2009, we had estimated proved reserves that totaled 153.6 Bcfe, of which 86.5% were proved developed, with an after-tax PV-10 value of $156.7 million. For the year ended December 31, 2009, we reported net production of 60.7 Mmcfe per day.

As of December 31, 2009, our proved reserves were comprised of approximately 126.7 Bcf of natural gas and 4.5 Mmbbls of crude oil, or 82.4% gas on an equivalent basis. Approximately 73% of our proved reserves were located in the Rocky Mountains, 26% in the Gulf Coast and less than 1% in other locations. We expect that our 2010 drilling efforts and capital expenditures, when announced, will focus primarily on our Piceance Basin assets in the Rockies, As of December 31, 2009, we controlled approximately 797,000 net undeveloped acres, representing approximately 98% 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% (excluding our Columbia River Basin properties) as of December 31, 2009. 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. We also have a controlling ownership interest in a drilling company, providing the benefit of access to 18 drilling rigs primarily located in the Rocky Mountain Region. We concentrate our exploration and development efforts in fields where we can apply our technical exploration and development expertise, and where we have accumulated significant operational control and experience.

2009 Developments

- On April 22, 2009, DHS entered into 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, acceleration of all amounts due under the credit agreement or foreclosure on the DHS rigs and other assets pledged as collateral, including accounts receivable. Because the forbearance period has expired and because of December 31, 2009 financial covenant violations by DHS, LCPI currently has the right to demand payment of the amounts outstanding under the credit facility and, if not paid, foreclose on the DHS assets pledged as collateral under the credit agreement. As of December 31, 2009, borrowings outstanding under the DHS facility were $83.3 million.

- On May 13, 2009, we completed an underwritten public offering of 172.5 million shares of our common stock at $1.50 per share for net proceeds of $246.9 million, net of underwriting commissions and related offering expenses.

- On May 15, 2009, we purchased for $26.0 million contingent payment rights previously sold to Tracinda Corporation that entitled Tracinda to receive up to $27.9 million of net proceeds from offshore California litigation related to the Amber Case.

- On May 19, 2009, we settled litigation filed in the United States Court of Federal Claims in Washington, D.C. by us and our 92%-owned subsidiary, Amber Resources Company of Colorado, with respect to 40 undeveloped federal leases, some of which were part of our and Amber's offshore California properties (the "Amber Case"), and received from the U.S. government $60.0 million of litigation proceeds. In early June 2009, we paid out $11.3 million of royalty payments to third parties related to the Amber Case.

- On September 21, 2009, Gray well completion results were announced. The well did not encounter commercial quantities of gas and was written off as a dry hole during the quarter ended September 30, 2009.

- In October 2009, we entered into a new marketing arrangement for the majority of our operated Piceance Basin gas. Although our new arrangement results in higher transportation costs (Vega gas transportation expense increased from approximately $0.60 per Mmbtu to $1.20 per Mmbtu), this increase is more than offset by higher revenues from improved natural gas liquids recoveries at a higher efficiency processing plant (liquids recovery factor increased from approximately 0.25 gallons per Mmbtu compared to 2.75 gallons per Mmbtu) and a greater percentage of liquid proceeds retained (increased from approximately 67% of proceeds to 100% of proceeds). As a result of these changes, based on current commodity prices, our net realized price prior to hedging in the Vega area has improved substantially.

- In November 2009, we retained Strategic Advisors to evaluate and advise the Board of Directors on strategic alternatives to enhance shareholder value and the process is currently in advanced stages. Such alternatives are expected to include, but may not be limited to, exploring the sale of some or all of our assets, entering into partnerships or joint ventures, or the sale of the entire company. There can be no assurance that this evaluation of strategic alternatives will result in changes to our company, operations or business plan. In addition, there can be no assurance that we will pursue any particular transaction or transactions, or, if we do pursue any such transaction, that it will be completed or successful.

- On December 29, 2009, we settled the Lease 452 Case and received from the U.S. government $65.0 million of offshore litigation proceeds related to that case. In December 2009 and January 2010, we paid out $16.4 million of royalty payments to third parties related to the Lease 452 Case.

- As of December 31, 2009, we had reduced borrowings under our credit facility to $124.0 million, with $39.8 million of availability based on the October 30, 2009 redetermined $185.0 million borrowing base with a required availability cushion of $20.0 million. At February 28, 2010, our availability was $70.8 million. In addition, we obtained financial covenant relief for the quarters ending on December 31, 2009 and March 31, 2010.

2010 Outlook

As announced in November 2009, we are working with our Strategic Advisors to analyze various alternatives to enhance stockholder value, which include a sale of some or all of our assets, entering into partnerships or joint ventures, or the sale of the entire company. The evaluation of any particular transaction will involve, among other considerations, an analysis of our capital expenditure and working capital requirements for 2010 in respect of such transaction and other sources of liquidity, including cash from operations and our credit facility. We do not intend to disclose developments with respect to this review until the Board of Directors has approved a course of action.

We are unable to accurately predict our anticipated capital expenditures for fiscal year 2010, primarily due to the uncertainty relating to any Potential Strategic Transaction, including the likelihood of such a transaction occurring, the type of transaction and the timing of any such transaction. In addition, future redeterminations of our borrowing base under our credit facility, including the scheduled redetermination currently in process, may affect our liquidity available for capital expenditures making it difficult to accurately determine such amounts at the current time. We expect to announce our 2010 drilling plans and expected oil and gas production once our strategic alternatives evaluation process and borrowing base redetermination are complete.

The exploration for and the acquisition, development, production, and sale of, natural gas and crude oil are highly competitive and capital intensive. As in any commodity business, the market price of the commodity produced and the costs associated with finding, acquiring, extracting, and financing the operation are critical to our profitability and long-term value creation for our stockholders. Generating long-term reserve and production growth represents an ongoing focus for management and is made particularly important in our business given the natural production and reserve decline associated with producing oil and gas properties.

Our long-term business strengths include a multi-year inventory of attractive lower risk drilling on long-lived Rockies properties, which we believe will allow us to grow reserves and replace and expand production organically without having to rely solely on acquisitions, and significant leasehold positions in several high potential exploratory areas.

Liquidity and Capital Resources

Cash Flows

On May 13, 2009, we completed an underwritten public offering of 172.5 million shares of our common stock at $1.50 per share for net proceeds of $246.9 million, net of underwriting commissions and related offering expenses. On May 19, 2009, we received from the U.S. government $60.0 million of offshore litigation proceeds related to the Amber Case and in early June 2009 we paid out $11.3 million for third party contractual obligations and other participating interests related to the judgment. Further, on December 29, 2009 we received from the U.S. government an additional $65.0 million of litigation proceeds related to the offshore California lease 452 and in late December 2009 and early January 2010, we paid out a total of $16.4 million for third party contractual obligations and other participating interests related to the judgment. With proceeds from these transactions, we have reduced our borrowings outstanding under our credit facility from $294.5 million at December 31, 2008 to $124.0 million at December 31, 2009, with $39.8 million of remaining availability based on our current $185.0 million borrowing base with a required minimum availability of $20.0 million and outstanding letters of credit totaling $1.2 million. The borrowing base is subject to a redetermination currently in process and could increase or decrease based on our reserves at such time. In addition, we reduced our accounts payable from $159.0 million at December 31, 2008 to $44.2 million at December 31, 2009. During May 2009, DHS sold Rig #7 to Naknek Electric Association for cash proceeds of $7.8 million which, combined with proceeds from minor spare equipment sales and the collection of accounts receivable, were used to reduce borrowings outstanding under the DHS credit facility from $93.8 million at December 31, 2008 to $83.3 million at December 31, 2009.

As shown in the accompanying financial statements and discussed elsewhere herein, we experienced a net loss attributable to Delta common stockholders of $328.8 million for the year ended December 31, 2009. We were in compliance with the capital expenditure and accounts payables covenants under our credit facility at December 31, 2009. In the Second Amendment, we obtained waivers of our financial ratio covenants for periods ending December 31, 2009 and March 31, 2010. In addition, our DHS subsidiary remained out of compliance with the debt covenants under its credit facility and its forbearance agreement with LCPI expired on June 15, 2009. As a result, amounts outstanding under the DHS credit facility are classified as a current liability in the accompanying consolidated balance sheet as of December 31, 2009. Further, DHS is facing significant, potentially immediate, requirements to fund obligations in excess of its existing sources of liquidity if its senior lender exercises its right to demand payment of the amounts outstanding under DHS's credit facility. DHS is in discussions with its credit facility lender regarding amendments, waivers or other restructuring of the credit facility, but there can be no assurance that the lender will agree to any such amendments.

Our accompanying financial statements have been prepared assuming we will continue as a going concern. During the year ended December 31, 2009, significant improvements to our liquidity position were achieved through the equity transaction, receipt of the offshore litigation proceeds, and asset sales described above, which substantially improved our financial position. Nevertheless, we have a deficiency in short-term liquidity at DHS and possible additional liquidity issues if commodity prices remain at low levels and our banks further reduce our borrowing base as part of our next scheduled redetermination which is currently in process. Further, our Credit Agreement matures in January 2011. Thus, our ability to continue as a going concern could be dependent upon our lenders' willingness to amend terms, grant waivers, or restructure existing agreements, or our success in generating additional sources of capital in the near future, and/or an increase in commodity prices. We are in discussions with our lenders regarding an amendment or restructuring of the existing credit facility, as well as discussions regarding a possible new credit facility.

During the year ended December 31, 2009, we had an operating loss of $254.4 million, net cash provided by operating activities of $81.1 million and net cash provided by financing activities of $62.7 million. During this period we spent $165.9 million on oil and gas development activities. At December 31, 2009, we had $61.9 million in cash and $39.8 million available under our credit facility (based on the borrowing base as re-determined on October 30, 2009), total assets of $1.5 billion and a debt to capitalization ratio of 39.8%. Debt, excluding installments payable on property acquisition which are secured by restricted cash deposits, at December 31, 2009 totaled $460.9 million, comprised of $207.3 million of bank debt ($124.0 million of our indebtedness under our Credit Agreement and $83.3 million of DHS indebtedness, of which the DHS indebtedness was classified as current at September 30, 2009), $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.

Capital Resources and Requirements

On March 2, 2009, we entered into the First Amendment to the Second Amended and Restated Credit Agreement (the "Forbearance Agreement and Amendment to the Credit Facility"), as further amended on April 14, 2009 and on April 30, 2009, with JPMorgan Chase Bank, N.A., as administrative agent, and certain of the financial institutions that are party to our credit agreement in which, among other changes, the lenders provided us relief for a period ended May 15, 2009 from acting upon their rights and remedies as a result of our violation of accounts payable and current ratio covenants. The Forbearance Agreement and Amendment to the Credit Facility replaced the previous consolidated net debt to consolidated EBITDAX covenant with a senior secured debt to consolidated EBITDAX requirement for the preceding four consecutive fiscal quarters to be less than 4.0 to 1.0. In accordance with the Forbearance Agreement and Amendment to the Credit Facility, the borrowing base was reduced upon the successful completion of our capital raising efforts from $295.0 million to $225.0 million, with a conforming borrowing base of $185.0 million.

On October 30, 2009, we entered into the Second Amendment in which, among other changes, the lenders provided waivers from the December 31, 2009 and March 31, 2010 current ratio and consolidated secured debt to EBITDAX ratio covenants. In conjunction with the Second Amendment and as part of a scheduled redetermination, the borrowing base was reduced from $225.0 million to $185.0 million. The next scheduled semi-annual redetermination is currently in progress. Also, the Second Amendment requires that we maintain minimum availability of $20.0 million essentially reducing our borrowing availability under the Credit Agreement. The minimum availability requirement will be released on the first date after delivery of the December 31, 2009 audited financial statements on which we are in compliance with our financial covenants as of the most recently completed quarter (without giving effect to any waiver of compliance with such covenants) and project pro forma compliance for each of the four following quarters. In addition, the Second Amendment imposed capital expenditures limitations of $10.0 million for the quarter ending December 31, 2009, $10.0 million for the quarter ending March 31, 2010, and $5.0 million for the quarter ending June 30, 2010, provided that any excess of the limitation over the amount of actual expenditures may be carried forward from an earlier quarter to a subsequent quarter. The Second Amendment also included a payables covenant whereby our trade payables (a sub-component of accounts payable on the accompanying consolidated balance sheet) may not exceed $30.0 million, exclusive of any amounts owed by us to our subsidiary DHS. As of December 31, 2009, we were in compliance with our capital expenditures and accounts payable limitations.

As of December 31, 2009, 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, 2009, 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 "developing."

Our future cash requirements are largely dependent upon the number and timing of projects included in our capital development plan, most of which are discretionary. We have historically addressed our long-term liquidity requirements through the issuance of debt and equity securities when market conditions permit, through cash provided by operating activities, sales of oil and gas properties, and through borrowings under our credit facility.

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. We are unable to predict with any degree of certainty the prices we will receive for our future oil and gas production and the success of our exploration and development activities in generating additional production.

There can be no assurance that the actions undertaken by us will be sufficient to repay the obligations under our credit facility, or, if not, or if additional defaults occur under that facility, that the lenders will be willing to waive further defaults or amend the facility. There can be no assurance that DHS's lender will not exercise its right to demand payment of the amounts outstanding under the DHS credit facility and, if not paid, foreclose on the DHS assets pledged as collateral for the credit facility. There can similarly be no assurance that our current levels of borrowing capacity under the Credit Agreement will remain in place, or that we will be successful in negotiating an extension to the Credit Agreement, or a replacement thereto, upon its scheduled maturity in January 2011. In addition, there can be no assurance that results of operations and other sources of liquidity, including asset sales and offshore litigation proceeds, will be sufficient to meet contractual, operating and capital obligations. Our financial statements do not include any adjustments that might result from the outcome of uncertainty regarding our ability to raise additional capital, sell assets, otherwise obtain sufficient funds to meet our obligations or to continue as a going concern.

As part of our consideration of Potential Strategic Transactions, we continue to examine additional sources of long-term capital (including a restructured debt facility, the issuance of debt instruments, sales of assets and joint venture financing), as well as other potential corporate transactions. The availability of additional sources of capital, which will impact our ability to execute our operating strategy and meet our liquidity challenges, will depend upon a number of factors, many of which are beyond our control.

Results of Operations

The following discussion and analysis relates to items that have affected our results of operations for the years ended December 31, 2009, 2008 and 2007. 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,		
	2009	2008	2007
Revenue:			
Oil and gas sales	$ 94,962	$ 221,733	$ 123,729
Contract drilling and trucking fees	13,680	49,445	58,358
Gain on offshore litigation settlement, net of property sales	73,800	-	-
Gain (loss) on hedging instruments, net	-	-	12,854
Total revenue	182,442	271,178	194,941
Operating Expenses:			
Lease operating expense	31,303	33,508	20,882
Transportation expense	11,612	11,395	4,074
Production taxes	3,852	12,075	7,463
Exploration expense	2,604	10,975	9,062
Dry hole costs and impairments	189,072	438,963	87,459
Depreciation, depletion and amortization – oil and gas	108,505	99,125	73,875
Drilling and trucking operating expenses	15,293	32,594	37,698
Goodwill and drilling equipment impairments	6,508	29,349	-
Depreciation and amortization – drilling and trucking	22,917	14,134	16,021
General and administrative expense	41,414	53,607	49,621
Executive severance expense	3,739	-	-
Total operating expenses	436,819	735,725	306,155
Operating loss	(254,377)	(464,547)	(111,214)
Other income and (expense):			
Interest expense and financing costs	(55,035)	(45,489)	(31,899)
Interest income	2,454	10,132	2,080
Other income (expense)	1,049	(5,210)	376
Realized gain (loss) on derivative instruments, net	(1,115)	18,383	917
Unrealized gain (loss) on derivative instruments, net	(26,972)	3,365	(3,819)
Income (loss) from unconsolidated affiliates	(15,473)	3,375	(393)
Total other expense	(95,092)	(15,444)	(32,738)
Loss from continuing operations before income taxes and discontinued operations	(349,469)	(479,991)	(143,952)
Income tax expense (benefit)	215	(11,723)	5,010
Loss from continuing operations	(349,684)	(468,268)	(148,962)
Income from discontinued operations of properties sold or held for sale, net of tax	-	-	1,922
Gain (loss) on sale of discontinued operations, net of tax	-	718	(3,998)
Net loss	(349,684)	(467,550)	(151,038)
Less net loss attributable to non-controlling interest	20,901	11,486	1,231
Net loss attributable to Delta common stockholders	$ (328,783)	$ (456,064)	$ (149,807)

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 $468.3 million for the year ended December 31, 2008 to a loss of $349.7 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 $95.0 million, as compared to $221.7 million for the comparable period a year earlier. During the year ended December 31, 2009, production from continuing operations decreased by 11% and the average natural gas and oil price decreased 54% and 43% respectively. The average gas price received during the year ended December 31, 2009 was $3.13 per Mcf compared to $6.87 per Mcf for the year earlier period and the average oil price received during the year ended December 31, 2009 was $52.37 per Bbl compared to $92.12 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. At December 31, 2009 DHS owned 18 drilling rigs with depth ratings of approximately 10,000 to 25,000 feet. We have the right to use all of the rigs on a priority basis, although currently only one is working on a Delta operated well. 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 and Property Sales, Net. 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)	761	993
Gas (MMcf)	17,590	18,948
Total Production (MMcfe)	22,156	24,908
Average Price – Continuing Operations:		
Oil (per barrel)	$ 52.37	$ 92.12
Gas (per Mcf)	$ 3.13	$ 6.87
Costs per Mcfe – Continuing Operations:		
Lease operating expense	$ 1.41	$ 1.35
Production taxes	$ .17	$ .48
Transportation costs	$ .52	$ .46
Depletion expense	$ 4.76	$ 3.87

Lease Operating Expense. Lease operating expenses for the year ended December 31, 2009 were $31.3 million compared to $33.5 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 declining production. The average lease operating expense was $1.41 per Mcfe in 2009 as compared to $1.35 per Mcfe for the year earlier period.

Transportation expense. Transportation expense for the year ended December 31, 2009 was $11.6 million, comparable to prior year costs of $11.4 million, but up 13% from $0.46 per Mcfe to $0.52 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 we expect Vega area transportation costs to increase on a per unit basis in 2010 as a result of these operations, based on current commodity prices, this increase is expected to be 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. 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 period a year ago. 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 to our proved and unproved properties totaling approximately $155.5 million primarily related to our non-operated Garden Gulch field in the Piceance Basin ($38.6 million), Haynesville Shale ($27.5 million), Columbia River Basin ($21.4 million), Lighthouse Bayou ($14.8 million), various Gulf Coast fields ($29.2 million), Vega surface land ($10.5 million), various Rockies fields ($6.9 million), pipe and tubular inventory ($4.3 million) and Paradox pipeline ($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 to our proved and unproved properties totaling approximately $305.6 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas ($192.5 million), Paradox field in Utah ($30.5 million), Howard Ranch and Bull Canyon fields in the Rockies ($32.0 million), Utah Hingeline ($40.8 million) and our offshore California field ($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 9% to $108.5 million for the year ended December 31, 2009, as compared to $99.1 million for the year earlier period. Depletion expense for the year ended December 31, 2009 was $105.4 million compared to $96.5 million for the year ended December 31, 2008. The 9% increase in depletion expense was primarily due to a 23% increase in the depletion rate. Our depletion rate increased to $4.76 per Mcfe for the year ended December 31, 2009 from $3.87 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. Based on current commodity prices, we expect our depletion rate to decline in 2010 due to additional Rockies undeveloped reserves that can be recorded as proved as higher prices from more recent quarters replace lower prices from earlier in 2009 in the SEC required 12-month average historical price.

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 decreased 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. We expect further reductions to full year cash general and administrative expenses in 2010 as cost saving measures implemented in 2009 take full effect in 2010.

Interest and Financing Costs. Interest and financing costs increased 21% to $55.0 million for the year ended December 31, 2009, as compared to $45.5 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, and non-cash accretion of discount on an installment obligation payable to EnCana Oil and Gas (USA) Inc. ("EnCana").

Interest Income. Interest income decreased to $2.5 million for the year ended December 31, 2009 compared to $10.1 million for the comparable prior year period. The decrease is a result of lower interest earned on lower investment balances.

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 on Derivative Instruments, Net. Effective July 1, 2007, we discontinued cash flow hedge accounting. Beginning July 1, 2007, we recognize realized gains or losses in other income and expense instead of as a component of revenue. As a result, other income and expense includes $1.1 million of realized losses and $18.4 million of realized gains on derivative instruments for the years ended December 31, 2009 and 2008, respectively.

Unrealized Gain on Derivative Instruments, Net. As a result of the discontinuation of cash flow hedge accounting, 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 loss 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 lower commodity prices in the current year period.

Income (Loss) From Unconsolidated Affiliates. Loss from unconsolidated affiliates during the year ended December 31, 2009 is 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 are 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 continued losses, we were required by the "more likely than not" provisions of SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), to record a valuation allowance for our deferred tax assets beginning with the second quarter of 2007. Our income tax benefit for the year ended December

31, 2009 of $215,000 relates only to DHS, as no benefit was provided for Delta's net operating losses.

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.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Net Income (Loss) Attributable to Delta Common Stockholders. Net loss attributable to Delta common stockholders was $456.1 million, or $4.77 per diluted common share, for the year ended December 31, 2008, compared to net loss of $149.8 million or $2.44 per diluted common share, for the year ended December 31, 2007. Loss from continuing operations attributable to Delta common stockholders increased from $147.7 million for the year ended December 31, 2007 to a loss of $456.8 million for the year ended December 31, 2008, due primarily to $327.1 million of impairments recorded during the fourth quarter due to the significant decline in commodity prices. In addition, we recognized $111.9 million of dry hole costs in the Paradox, Hingeline and other areas.

Oil and Gas Sales. During the year ended December 31, 2008, oil and gas sales from continuing operations were $221.7 million, as compared to $123.7 million for the comparable period a year earlier. During the year ended December 31, 2008, production from continuing operations increased by 48% and the average gas price increased 33%. The average gas price received during the year ended December 31, 2008 was $6.87 per Mcf compared to $5.17 per Mcf for the year earlier period. The average oil price received during the year ended December 31, 2008 increased to $92.12 per Bbl compared to $67.39 per Bbl for the year earlier period.

Net gains from effective hedging activities were $12.9 million for the year ended December 31, 2007. The gain in 2007 relates to effective hedging instruments during the period. These gains are recorded as an increase in revenues. For the year ended December 31, 2008, all realized derivative gains are included in other income.

Contract Drilling and Trucking Fees. At December 31, 2008 DHS owned 19 drilling rigs with depth ratings of approximately 10,000 to 25,000 feet. We have the right to use all of the rigs on a priority basis, although currently only two are working on Delta operated wells. Drilling and trucking revenues for the year ended December 31, 2008 decreased to $49.4 million compared to $58.4 million for the prior year period. Drilling and trucking revenues decreased in 2008 due to the average number of rigs working for Delta from 9 average rigs in 2008 compared to 6 average rigs for the prior year. Drilling and trucking revenues earned on wells drilled for Delta have been eliminated in consolidation.

Production and Cost Information

Production volumes, average prices received and cost per equivalent Mcf for the years ended December 31, 2008 and 2007 are as follows:

	Years Ended December 31,	
	2008	2007
Production – Continuing Operations:		
Oil (MBbl)	993	1,003
Gas (MMcf)	18,948	10,866
Production – Discontinued Operations:		
Oil (MBbl)	-	82
Gas (MMcf)	-	387
Total Production (MMcfe)	24,908	17,763
Average Price – Continuing Operations:		
Oil (per barrel)	$ 92.12	$ 67.39
Gas (per Mcf)	$ 6.87	$ 5.17
Costs per Mcfe – Continuing Operations:		
Lease operating expense	$ 1.35	$ 1.24
Production taxes	$ .48	$ .44
Transportation costs	$ .46	$ .24
Depletion expense	$ 3.87	$ 4.26

Lease Operating Expense. Lease operating expenses for the year ended December 31, 2008 were $33.5 million compared to $20.9 million for the year earlier period. Lease operating expense from continuing operations for the year ended December 31, 2008 increased proportionately with production. The average lease operating expense per Mcfe was $1.35 per Mcfe as compared to $1.24 per Mcfe for the year earlier period.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the year ended December 31, 2008 were $11.0 million compared to $9.1 million for the year earlier period. 2008 exploration activities primarily include seismic shoots in two areas.

Dry Hole Costs and Impairments. We incurred dry hole costs of approximately $111.9 million for the year ended December 31, 2008 compared to $28.1 million for the comparable period a year ago. For the year ended December 31, 2008, our dry hole costs related primarily to Greentown and Hingeline exploratory projects in Utah. For the year ended December 31, 2007, the dry hole costs related primarily to seven exploratory projects, three in Texas, two in Wyoming, one in Colorado and one in Utah.

During the year ended December 31, 2008, we recorded an impairment provision to our proved and unproved properties totaling approximately $305.6 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas ($192.5 million), Paradox field in Utah ($30.5 million), Howard Ranch and Bull Canyon fields in the Rockies ($32.0 million), Utah Hingeline ($40.8 million) and our offshore California field ($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.

During the year ended December 31, 2007, we recorded impairments totaling approximately $59.4 million primarily related to the Howard Ranch and Fuller fields in Wyoming ($38.4 million and $10.3 million, respectively), and the South Angleton field in Texas ($9.7 million), primarily due to lower Rocky Mountain natural gas prices and marginally economic deep zones on the Howard Ranch Prospect.

Depreciation, Depletion and Amortization – oil and gas. Depreciation, depletion and amortization expense increased 34% to $99.1 million for the year ended December 31, 2008, as compared to $73.9 million for the year earlier period. Depletion expense for the year ended December 31, 2008 was $96.5 million compared to $71.9 million for the year ended December 31, 2007. The 34% increase in depletion expense was due to a 48% increase in production from continuing operations, slightly offset by a 9% decrease in the depletion rate. Our depletion rate decreased to $3.87 per Mcfe for the year ended December 31, 2008 from $4.26 per Mcfe for the year earlier period. The decrease is partially due to lower finding costs per Mcfe on our 2008 Rockies drilling program and the effect of impairments recorded in 2008.

Drilling and Trucking Operating Expenses. We had drilling and trucking operating expenses of $32.6 million during the year ended December 31, 2008 compared to $37.7 million during the year ended December 31, 2007. The significant decrease in expenses was due to the increase in the average number of rigs working for Delta in 2008 than in the prior year.

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, we also wrote off the entire amount of DHS's goodwill of $7.7 million.

Depreciation and Amortization – drilling and trucking. Depreciation and amortization expense – drilling and trucking decreased to $14.1 million for the year ended December 31, 2008 as compared to $16.0 million for the prior year period. This decrease can be attributed to a greater average number of rigs working for Delta in 2008 compared to the prior year.

General and Administrative Expense. General and administrative expense increased 8% to $53.6 million for the year ended December 31, 2008, as compared to $49.6 million for the comparable prior year period. The increase in general and administrative expenses is primarily attributed to an increase in staff and related personnel costs.

Interest and Financing Costs. Interest and financing costs increased 43% to $45.5 million for the year ended December 31, 2008, as compared to $31.9 million for the comparable year earlier period. The increase is primarily related to higher average debt balances on the Delta and DHS credit facilities and the non-cash accretion of discount on an installment obligation payable to EnCana Oil and Gas (USA) Inc. ("EnCana"). In addition, the year ended December 31, 2008 includes $4.2 million of non-cash accretion of debt discount compared to $2.7 million in the prior year period related to the 3¾% convertible notes issued in April 2007.

Interest Income. Interest income increased to $10.1 million for the year ended December 31, 2008 compared to $2.1 million for the comparable prior year period. The increase is primarily due to interest earned on our $300 million restricted deposit in connection with a joint development transaction with EnCana and invested cash received from the Tracinda transaction during the first quarter of 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.

Realized Gain on Derivative Instruments, Net. Effective July 1, 2007, we discontinued cash flow hedge accounting. Beginning July 1, 2007, we recognize realized gains or losses in other income and expense instead of as a component of revenue. As a result, other income and expense includes $18.4 million and $917,000 of realized gains on derivative instruments for the years ended December 31, 2008 and 2007, respectively.

Unrealized Gain on Derivative Instruments, Net. As a result of the discontinuation of cash flow hedge accounting, we recognize mark-to-market gains or losses in current earnings instead of deferring those amounts in accumulated other comprehensive income. Accordingly, we recognized $3.4 million of unrealized gains on derivative instruments in other income and expense during the year ended December 31, 2008 compared to a loss of $3.8 million for the comparable prior year period, primarily due to lower commodity prices in the current year period.

Income Tax Benefit (Expense). Due to our continued losses, we were required by the "more likely than not" provisions of SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), to record a valuation allowance for our deferred tax assets beginning with the second quarter of 2007. Our income tax benefit for the year ended December 31, 2008 of $11.7 million relates only to DHS, as no benefit was provided for Delta's net operating losses.

Discontinued Operations. Discontinued operations for the year ended December 31, 2007 include the Kansas field, which was sold in January 2007, the Australia field and the New Mexico and East Texas properties, which were sold in March 2007, the North Dakota properties sold in September 2007, and the Washington County, Colorado properties sold in October 2007. The results of operations from these assets during the year ended December 31, 2007 was an income of $1.9 million, net of tax.

Gain (Loss) on Sale of Discontinued Operations. 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. During the year ended December 31, 2007, we sold non-core properties in Colorado, Kansas, Texas, New Mexico, Australia and North Dakota for combined proceeds of $46.4 million at a combined net loss of $4.0 million.

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, 2008 and 2007, DHS generated a loss resulting in a non-controlling interest credit to earnings.

Historical Cash Flow

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 $147.4 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 provided by financing activities was $62.7 million for the year ended December 31, 2009 compared to $897.6 million for the comparable prior year period. Cash provided by 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 was higher in 2008 primarily due to cash received from the Tracinda transaction and additional bank borrowings.

Our cash flow from operating activities increased from $87.0 million for the year ended December 31, 2007 to $140.7 million for the year ended December 31, 2008, primarily as a result of increased production and higher commodity prices for most of the year. Our net cash used in investing activities increased to $982.6 million for the year ended December 31, 2008 compared to net cash used in investing activities of $326.6 million for the year earlier period, primarily due to our increased drilling and acquisition activity and the investment of cash received in the Tracinda transaction. Cash provided by financing activities was $897.6 million for the year ended December 31, 2008 compared to $241.7 million for the comparable prior year period. Cash provided by financing activities was higher in 2008 primarily due to cash received from the Tracinda transaction.

Capital and Exploration Expenditures and Financing

Our capital and exploration expenditures and sources of financing for the years ended December 31, 2009, 2008 and 2007 were as follows:

	Years Ended December 31,		
	2009	2008	2007
CAPITAL AND EXPLORATION EXPENDITURES:		(In thousands)	
Acquisitions:			
Piceance	$ -	$ 128,848	$ -
Haynesville	-	31,550	-
Lighthouse Bayou	-	14,512	-
Austin Chalk incremental interests	-	13,855	23,765
Garden Gulch	-	-	34,778
Wyoming (Yates)	-	-	3,500
Washington County, South and North Tongue	-	-	1,000
Columbia River Basin	-	25,000	-
Other	2,083	8,050	9,988
Other development costs	165,854	458,067	287,790
Drilling and trucking companies	1,785	52,970	22,292
Exploration costs	2,604	10,975	9,062
	$ 172,326	$ 743,827	$ 392,175
FINANCING SOURCES:			
Cash provided by operating activities	$ 81,144	$ 140,676	$ 87,003
Stock issued for cash upon exercised options	-	4,827	137
Stock issued for cash, net	246,905	662,043	202,084
Net long-term borrowings	(183,859)	232,120	40,836
Proceeds from sale of oil and gas properties	8,393	42,000	46,193
Proceeds from sale of drilling assets	9,111	3,201	7,145
Proceeds from sale of marketable securities	2,030	-	-
Investments in and notes issued to affiliates	295	(6,965)	(12,833)
Increase in restricted deposit	430	(300,000)	-
Minority interest contributions	-	12,000	(355)
Other	14	(120)	(106)
	$ 164,463	$ 789,782	$ 370,104

We are unable to accurately predict our anticipated capital expenditures for fiscal year 2010, primarily due to the uncertainty relating to any Potential Strategic Transaction, including the likelihood of such a transaction occurring, the type of transaction and the timing of any such transaction. In addition, future redeterminations of our borrowing base under our credit facility, including the scheduled redetermination currently in process, may affect our liquidity available for capital expenditures making it difficult to accurately determine such amounts at the current time. We expect to announce our 2010 drilling plans once our strategic alternatives evaluation process and borrowing base redetermination are complete.

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, 2007, positive gas revisions of 23.9 Bcf were primarily related to longer lived Piceance Basin wells due to higher gas pricing at year-end 2007 and the increase in proved reserves from extensions and discoveries of 100.8 Bcfe was primarily comprised of Rocky Mountain proved reserve increases primarily from the Company's Piceance Basin drilling program and related offset wells. In addition, during 2007, the Company purchased incremental interests in its existing Piceance Basin acreage and in its existing Gulf Coast Austin Chalk acreage totaling 12.2 Bcfe. Finally, during 2007, proved reserves totaling 33.3 Bcfe located in various states were sold in a series of transactions described in Note 4, "Oil and Gas Properties – Discontinued Operations" to the 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 the Company's 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 the Company's Piceance Basin drilling program and related offset wells. Also, 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 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. 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 the Company's 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.

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, 2007, 2008 and 2009, we completed the following transactions:

On October 1, 2007, we divested our Washington County, Colorado assets in conjunction with an asset exchange transaction to acquire additional working interest in the Garden Gulch Field in the Piceance Basin. On September 4, 2007, we completed the sale of certain non-core properties located in North Dakota for cash consideration of approximately $6.2 million. The sale resulted in a gain of $4.3 million. On March 30, 2007, we completed the sale of certain non-core properties located in New Mexico and East Texas for cash consideration of approximately $31.5 million, prior to customary purchase price adjustments. The sale resulted in a loss of approximately $10.8 million. On March 27, 2007, we completed the sale of certain non-core properties located in Australia for cash consideration of approximately $6.0 million. The sale resulted in an after-tax gain of $2.0 million. On January 10, 2007, we completed the sale of certain non-core properties located in Padgett field, Kansas for cash consideration of $5.6 million. The transaction resulted in a gain on sale of properties of $297,000.

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 34% of the Company's 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 the Company 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 leaseholds interests acquired from EnCana on September 15, 2008.

During the fourth quarter of 2009 through a series of transactions, the Company 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, the Company sold the amine unit from its 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.

Off-Balance Sheet Arrangements

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

Contractual Obligations

	For the years ending December, 31				
Contractual Obligations at December 31, 2009	2010	2011 - 2012	2013 - 2014	Thereafter	Total
			(In thousands)		
Credit facility	$ -	$ 124,038	$ -	$ -	$ 124,038
Installments payable on property acquisitions[1]	100,000	100,000	-	-	200,000
7% Senior unsecured notes	-	-	-	150,000	150,000
Interest on 7% Senior unsecured notes	10,500	21,000	21,000	10,500	63,000
3¾% Senior convertible notes[2]	-	115,000	-	-	115,000
Credit facility – DHS[3]	83,268	-	-	-	83,268
Derivative liability	19,497	7,475	-	-	26,972
Abandonment retirement obligation	2,913	592	365	16,869	20,739
Operating leases	2,447	2,992	2,922	946	9,307
Total contractual cash obligations	$ 218,625	$371,097	$ 24,287	$178,315	$ 792,324

[1]Amounts due will be funded with restricted cash deposits on hand.
[2]The convertible notes may be put to the Company by the holders of the notes in April 2012.
[3]Amounts outstanding under the DHS credit facility are classified as current due to their covenant violations at December 31, 2009. See Credit Facility – DHS below for additional information.

Credit Facility

On October 30, 2009, we entered into the Second Amendment in which, among other changes, our lender banks provided waivers from the December 31, 2009 and March 31, 2010 current ratio and consolidated secured debt to EBITDAX ratio covenants. In conjunction with the Second Amendment and as part of a scheduled redetermination, the borrowing base was reduced from $225.0 million to $185.0 million. The next scheduled redetermination date is March 1, 2010. Also, the Second Amendment requires that we maintain minimum availability of $20.0 million essentially reducing our borrowing availability under the Credit Agreement. Under the terms of the Second Amendment, the minimum availability requirement will be released on the first date after delivery of the December 31, 2009 audited financial statements on which we are in compliance with our financial covenants as of the most recently completed quarter (without giving effect to any waiver of compliance with such covenants) and project pro forma compliance for each of the four following quarters. In addition, the Second Amendment imposed capital expenditures limitations of $10.0 million for the quarter ending December 31, 2009, $10.0 million for the quarter ending March 31, 2010, and $5.0 million for the quarter ending June 30, 2010, provided that any excess of the limitation over the amount of actual expenditures may be carried forward from an earlier quarter to a subsequent quarter. The Second Amendment also included a payables covenant whereby our trade payables (a sub-component of accounts payable on the accompanying consolidated balance sheet) may not exceed $30.0 million, exclusive of any amounts owed by us to our subsidiary DHS. As of December 31, 2009, we were in compliance with our capital expenditures and trade payables covenants.

The borrowing base is redetermined by the lending banks at least semiannually or by special redeterminations if requested by us based on drilling success. The March 2010 scheduled redetermination is in process. 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 three equal monthly principal payments, (3) provide additional collateral for consideration to eliminate the deficiency within 90 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 Credit Agreement.

The 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 lending banks on most of our oil and gas properties, certain related equipment, and oil and gas inventory.

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 and the remaining balance is due in two $100.0 million installments due November 1, 2010, and 2011. These remaining installments are 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 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 $6.1 million and $7.0 million for the years ended December 31, 2008 and 2009, 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 August 15, 2008, DHS entered into a new agreement with Lehman Commercial Paper, Inc. ("LCPI") to amend its existing LCPI 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 does not have any additional borrowing capacity under the LCPI facility. Under the revised agreement, DHS has 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. In addition, 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.

On April 22, 2009, DHS entered into 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, acceleration of all amounts due under the credit facility or foreclosure on the DHS rigs and other assets pledged as collateral, including accounts receivable. The DHS facility is non-recourse to Delta. Due to the lapsing of the DHS Forbearance as well as the September 30, 2009 and December 31, 2009 financial covenant violations by DHS, LCPI currently has the right to demand payment of the amounts outstanding under the credit facility and if not paid, foreclose on the DHS assets pledged as collateral for the credit facility. Although LCPI has not exercised its right to foreclose on the DHS assets pledged as collateral and DHS in currently in negotiations with LCPI to amend the terms of the credit facility, there can be no assurance that LCPI will not exercise its right to foreclose on the DHS assets pledged as collateral.

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 will not 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 $27.0 million at December 31, 2009. 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. Based on the 12-month average historical first of month prices required to be used under the new SEC reserve reporting rules in determining proved reserves, none of our undeveloped locations in the Piceance Basin were able to be classified as proved undeveloped reserves at December 31, 2009. However, based on the old SEC rules, we would be able to report our Piceance Basin proved undeveloped reserves (see Reserve Sensitivities in Item 2. Properties above) as a result of higher prices at year-end 2009. Further development of these properties depends on expected higher commodity prices in the future, reductions in future drilling costs, or a combination of both.

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, 2009, we recorded impairment provisions to our proved and unproved properties totaling approximately $155.5 million primarily related to our non-operated Garden Gulch field in the Piceance Basin ($38.6 million), Haynesville Shale ($27.5 million), Columbia River Basin ($21.4 million), Lighthouse Bayou ($14.8 million), proved and unproved impairments in various Gulf Coast fields ($29.2 million), Vega surface land ($10.5 million), proved and unproved impairments in various Rockies fields ($6.9 million), pipe and tubular inventory ($4.3 million) and Paradox pipeline ($1.9 million).

In 2008, we recorded impairment provisions to our proved and unproved properties totaling approximately $305.6 million primarily related to the Newton, Midway Loop, Opossum Hollow and Angleton fields in Texas ($192.5 million), Paradox field in Utah ($30.5 million), Howard Ranch and Bull Canyon fields in the Rockies ($32.0

million), Utah Hingeline ($40.8 million) and our offshore California field ($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 ($21.5 million), certain DHS rigs ($21.6 million) and we wrote off DHS's goodwill ($7.7 million).

During the year ended December 31, 2007, an impairment of $59.4 million was recorded primarily related to the Howard Ranch and Fuller fields in Wyoming ($38.4 million and $10.3 million, respectively), and the South Angleton field in Texas ($9.7 million), primarily due to lower Rocky Mountain natural gas prices and marginally economic deep zones on the Howard Ranch Prospect. During the year ended December 31, 2006, an impairment of $10.4 million was recorded on certain of the Company's eastern Colorado properties primarily due to lower Rocky Mountain natural gas prices. In addition, an impairment of $1.0 million was recorded on certain Oklahoma properties.

For fiscal year 2010, 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' future cash flows. Such revisions of estimates could require us to record an impairment in the period of such revisions.

Commodity Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the balance sheet at fair value which must be estimated using complex valuation models. Effective July 1, 2007, we elected to discontinue cash flow hedge accounting prospectively. Beginning July 1, 2007, 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, 2009, we had a total of seven oil and gas derivative contracts outstanding. The fair value of our oil derivative instruments was a liability of $14.7 million and the fair value of our gas derivative instruments was a liability of $12.3 million at December 31, 2009. The liability is discounted based on our credit-worthiness 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, 2009. The pre-credit risk adjusted fair value of our net derivative liabilities as of December 31, 2009 was $29.5 million. A credit risk adjustment of $2.5 million to the fair value of the derivatives reduced the reported amount of the net derivative liabilities on our consolidated balance sheet to $27.0 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 follow SFAS 109 to account for our deferred tax assets and liabilities. Under SFAS 109, 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 Adopted Accounting Pronouncements

In December 2008, the SEC approved new rules designed to modernize oil and gas reserve reporting requirements. The most significant amendments to the requirements included the following:

- Commodity Prices – Economic producibility of reserves and discounted cash flows is now based on a 12-month average commodity price unless contractual arrangements designate the price to be used.
- Disclosure of Unproved Reserves – Probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved Undeveloped Reserves Guidelines – Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years.
- Reserves Estimation Using New Technologies – Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserves Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Non-Traditional Resources – The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009. In addition, in January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (Update) 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the new SEC rules. The Update amends existing standards to align the reserves calculation and disclosure requirements under US GAAP with the requirements in the SEC rules. We adopted the new standards effective December 31, 2009. The new standards are applied prospectively as a change in estimate. See also Note 19, "Information Regarding Proved Oil and Gas Reserves (Unaudited)", to our accompanying consolidated financial statements.

In March 2008, the FASB issued authoritative guidance related to the accounting for convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). The guidance requires the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (debt issued at a discount) and an equity component. The resulting debt discount is amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. This guidance was adopted effective January 1, 2009. This guidance changes the accounting treatment for our 3¾% Senior Convertible Notes issued April 25, 2007 and was applied retrospectively upon adoption. The fair value of the liability and equity components was determined based on our estimated borrowing rate at the date of issuance and, as a result, the liability component was approximately $92.7 million and the equity component was approximately $22.3 million. Based on these components at the issue date we recorded a reduction to the carrying value of the Notes of $22.3 million upon adoption of the guidance, with a corresponding increase in additional paid in capital. The accompanying consolidated financial statements include accretion of the resulting debt discount of approximately $1.1 million and $4.4 million for the three months and year ended December 31, 2009 and approximately $1.0 million and $4.2 million for the three months and year ended December 31, 2008. The remaining discount will be amortized through May 2012 when the holders of the Notes can first require us to purchase all or a portion of the Notes. Combined with the amortization of debt discount, the Notes have an effective interest rate of approximately 7.6% and 7.4% with total interest costs of $8.7 million and $8.5 million for the years ended December 31, 2009 and 2008, respectively.

In March 2008, the FASB issued new rules related to disclosures about derivative instruments and hedging activities which required enhanced disclosures for derivative and hedging activities. These rules were effective for us on January 1, 2009. We have included the new required disclosures in these financial statements.

In December 2007, the FASB issued new rules which established accounting and reporting standards for non-controlling interests ("minority interests") in subsidiaries. These rules clarified that a non-controlling interest in a subsidiary should be accounted for as a component of equity separate from the parent's equity. The rules were effective for us on January 1, 2009 and must be applied prospectively, except for the presentation and disclosure requirements, which have been applied retrospectively. The adoption of these rules had the effect of increasing total equity by the amount of the non-controlling interest and changing other presentations in the accompanying financial statements.

In April 2009, the FASB issued revised authoritative guidance requiring disclosures about fair value of financial instruments. The adoption of this guidance did not have a material impact on our consolidated financial statements, other than additional disclosures. The guidance provided additional clarification for estimating fair value when the volume and level of activity for the asset or liability have significantly decreased and requires that companies provide interim and annual disclosures of the inputs and valuation technique(s) used to measure fair value. This guidance was effective for interim and annual reporting periods ending after June 15, 2009 with such disclosures included herein as applicable.

In April 2009, the FASB issued revised authoritative guidance related to interim disclosures about fair value of financial instruments. The adoption of this guidance did not have an impact on our consolidated financial statements, other than requiring additional disclosures. The guidance required disclosures about fair value of financial instruments in financial statements for interim reporting periods of publicly traded companies as well as in annual financial statements and was effective for interim and annual reporting periods ending after June 15, 2009. Such disclosures have been included herein as applicable.

In May 2009, the FASB issued authoritative guidance which incorporated the principles and accounting guidance for recognizing and disclosing subsequent events that originated as auditing standards into the body of authoritative literature issued by the FASB, and prescribes disclosures regarding the date through which subsequent events have been evaluated. In particular, the guidance set forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The guidance was effective for us beginning with the Quarterly Report on Form 10-Q for the quarter ended June 30, 2009. The implementation of this guidance did not have a material impact on our financial statements. Subsequent events were evaluated through the date of issuance of these consolidated financial statements at the time this Annual Report on Form 10-K was filed with the Securities and Exchange Commission.

Recently Issued Accounting Pronouncements

Applicable recently issued accounting pronouncements have been adopted as of December 31, 2009. Please refer to "recently adopted accounting pronouncements" disclosure above for further information.

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 limit the risk of fluctuating cash flows that fund our capital expenditure program. 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, 2009:

Commodity	Volume		Fixed Price	Term		Index Price	Net Fair Value Asset (Liability) at December 31, 2009 (In thousands)
Crude oil	1,000	Bbls / Day	$ 52.25	Jan '10	- Dec '10	NYMEX – WTI	(10,338)
Crude oil	500	Bbls / Day	$ 57.70	Jan '11	- Dec '11	NYMEX – WTI	(4,374)
Natural gas	6,000	MMBtu / Day	$ 5.720	Jan '10	- Dec '10	NYMEX – HHUB	(135)
Natural gas	15,000	MMBtu / Day	$ 4.105	Jan '10	- Dec '10	CIG	(6,467)
Natural gas	5,367	MMBtu / Day	$ 3.973	Jan '10	- Dec '10	CIG	(2,558)
Natural gas	12,000	MMBtu / Day	$ 5.150	Jan '11	- Dec '11	CIG	(2,352)
Natural gas	3,253	MMBtu / Day	$ 5.040	Jan '11	- Dec '11	CIG	(748)
							$(26,972)

Assuming production and the percent of oil and gas sold remained unchanged from the year ended December 31, 2009 a hypothetical 10% decline in the average market price we realized during the year ended December 31, 2009 on unhedged production would reduce our oil and natural gas revenues by approximately $9.5 million on an annual basis.

Interest Rate Risk

We were subject to interest rate risk on $207.3 million of variable rate debt obligations at December 31, 2009. The annual effect of a 10% change in interest rates would be approximately $1.1 million. The interest rate on these variable debt obligations approximates current market rates as of December 31, 2009.

As of December 31, 2009, we have fixed rate debt totaling $253.6 million. The fair value of the fixed rate debt as of December 31, 2009 was approximately $189.7 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, 2009. 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, 2009, 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, 2009, 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, 2009.

Changes in Internal Controls

There were no changes in internal control over financial reporting that occurred during the fourth quarter of 2009 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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 the Company's definitive Proxy Statement which will be filed with the Securities and Exchange Commission in connection with the 2010 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 62 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

2.1 Agreement and Plan of Merger, dated as of November 8, 2005, among Delta Petroleum Corporation, a Colorado corporation, Delta Petroleum Corporation, a Delaware corporation, DPCA LLC, a Delaware limited liability company, and Castle Energy Corporation, a Delaware corporation. Incorporated by reference to Appendix A to the proxy statement/prospectus contained in the Company's Form S-4 filed December 23, 2005.

3.1 Certificate of Incorporation of the Company, as amended. Incorporated by reference to Exhibit 3.1 to the Company's 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 the Company's 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 the Company's 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 the Company's 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 the Company's 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 the Company's Form 8-K filed March 21, 2005.

4.5 Indenture, dated as of April 25, 2007, by and between the Company 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 the Company's 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 the Company's Form 8-K filed April 25, 2007.

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

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

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

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

10.5 Delta Petroleum Corporation 2004 Incentive Plan. Incorporated by reference to Appendix B to the Company's 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 the Company's 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 the Company's 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 the Company's 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 the Company's 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 the Company's 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 the Company's 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. Filed herewith electronically.*

10.13 Employment Agreement with Kevin K. Nanke dated May 5, 2005. Incorporated by reference to Exhibit 10.2 to the Company's Form 8-K filed May 11, 2005.*

10.14 Employment Agreement with John R. Wallace dated May 5, 2005. Incorporated by reference to Exhibit 10.3 to the Company's 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 the Company's Form 8-K filed January 12, 2006.*

10.16 Change in Control Executive Severance Agreement with John R. Wallace dated April 30, 2007. Incorporated by reference to Exhibit 10.2 to the Company's Form 8-K filed May 2, 2007.*

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

10.19 Severance Agreement by and between Delta Petroleum Corporation and Roger Parker, dated May 26, 2009. Incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed June 1, 2009.

10.20 Second Amended and Restated Credit Agreement dated November 3, 2008, among the Company, JPMorgan Chase Bank, N.A. as Administrative Agent, Bank of Montreal as Syndication Agent, U.S. Bank National Association as Documentation Agent and the financial institutions named therein. Incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed November 5, 2008.

10.21 First Amendment to Second Amended and Restated Credit Agreement dated effective March 2, 2009, among the Company, JPMorgan Chase Bank, N.A. as Administrative Agent, and the financial institutions named therein. Incorporated by reference to Exhibit 10.32 to the Company's Form 10-K for the annual period ended December 31, 2008 and filed March 2, 2009.

10.22 Amendment Letter to First Amendment to Second Amended and Restated Credit Agreement dated April 14, 2009, among Delta Petroleum Corporation, JPMorgan Chase Bank, N.A. and certain other financial institutions named therein. Incorporated by reference to Exhibit 10.3 to the Company's Form 8-K filed April 15, 2009.

10.23 Second Amendment Letter to First Amendment to Second Amended and Restated Credit Agreement, dated April 30, 2009, by and among Delta Petroleum Corporation, JPMorgan Chase Bank, N.A. and certain other financial institutions named therein. Incorporated by reference to Exhibit 10.4 to the Company's Form 8-K filed May 1, 2009.

10.24 Second Amendment to Second Amended and Restated Credit Agreement, dated as of October 30, 2009, by and among the Company, JPMorgan Chase Bank, N.A. as Administrative Agent, and the financial institutions named therein. Incorporated by reference to Exhibit 10.3 to the Company's Form 10-Q for the quarterly period ended September 1, 2009 and filed November 5, 2009.

10.25 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 the Company's Form 10-Q for the quarterly period ended September 30, 2008 and filed November 6, 2008.

10.26 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 the Company's Form 10-Q for the quarterly period ended September 30, 2008 and filed November 6, 2008.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 the Company's Form 8-K filed March 5, 2008.

10.27 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 the Company's Form 10-Q for the quarterly period ended March 31, 2009 and filed May 5, 2009.

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

10.29 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 the Company's Form 8-K filed January 25, 2008.

10.30 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 the Company's Form 8-K filed October 2, 2008.

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

10.32 Contingent Payment Rights Purchase Agreement by and between the Company and Tracinda Corporation, dated as of March 26, 2009. Incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed April 1, 2009.

10.33 Contingent Payment Rights Repurchase Agreement by and between the Company and Tracinda Corporation, dated May 15, 2009. Incorporated by reference to Exhibit 10.1 to the Company's Form 8-K filed May 21, 2009.

10.34 Settlement Agreement between Delta Petroleum Corporation and the United States of America dated December 16, 2009. Filed herewith electronically.

21. 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, 2009. Filed herewith electronically.

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* Management contracts and compensatory plans.

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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, 2009, and 2008, 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, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2009, 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 the Company is evaluating strategic alternatives including, but not limited to the sale of some or all of its assets. 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, 2009, 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 11, 2010 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

As discussed in note 3 to the consolidated financial statements, Delta Petroleum Corporation changed how it accounted for Uncertainty in Income Taxes effective January 1, 2007. Delta Petroleum Corporation also changed its accounting for its convertible debt instrument that may be settled in cash upon conversions (including partial cash settlement) and how non-controlling Interests in Consolidated Financial Statements are presented in the financial statements, effective January 1, 2009 and these have been applied retrospectively to the consolidated financial statements.

/s/ KPMG LLP

Denver, Colorado
March 11, 2010

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, 2009, 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, 2009, 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, 2009 and 2008, 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, 2009, and our report dated March 11, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Denver, Colorado
March 11, 2010

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
ASSETS	(In thousands, except share data)	
Current assets:		
Cash and cash equivalents	$ 61,918	$ 65,475
Short-term restricted deposits	100,000	100,000
Trade accounts receivable, net of allowance for doubtful accounts of $100 and $652, respectively	16,654	30,437
Deposits and prepaid assets	3,103	11,253
Inventories	5,588	9,140
Deferred tax assets	-	231
Other current assets	5,189	6,221
Total current assets	192,452	222,757
Property and equipment:		
Oil and gas properties, successful efforts method of accounting:		
Unproved	280,844	415,573
Proved	1,379,920	1,365,440
Drilling and trucking equipment	177,762	194,223
Pipeline and gathering systems	92,064	86,076
Other	16,154	29,107
Total property and equipment	1,946,744	2,090,419
Less accumulated depreciation and depletion	(800,501)	(658,279)
Net property and equipment	1,146,243	1,432,140
Long-term assets:		
Long-term restricted deposit	100,000	200,000
Marketable securities	-	1,977
Investments in unconsolidated affiliates	7,444	17,989
Deferred financing costs	3,017	7,640
Other long-term assets	8,329	12,460
Total long-term assets	118,790	240,066
Total assets	$ 1,457,485	$ 1,894,963
LIABILITIES AND EQUITY		
Current liabilities:		
Credit facility – Delta	$ -	$ 294,475
Credit facility – DHS	83,268	-
Installments payable on property acquisition	97,874	97,453
Accounts payable	44,225	159,024
Offshore litigation payable	13,877	-
Other accrued liabilities	13,459	13,576
Derivative instruments	19,497	-
Total current liabilities	272,200	564,528
Long-term liabilities:		
Installments payable on property acquisition, net of current portion	95,381	188,334
7% Senior notes	149,609	149,534
3¾% Senior convertible notes	104,008	99,616
Credit facility - Delta	124,038	-
Credit facility - DHS	-	93,848
Asset retirement obligations	7,654	6,585
Derivative instruments	7,475	-
Deferred tax liabilities	-	1,024
Total long-term liabilities	488,165	538,941
Commitments and contingencies		
Equity:		
Preferred stock, $.01 par value: authorized 3,000,000 shares, none issued	-	-
Common stock, $.01 par value; authorized 300,000,000 shares, issued 282,548,000 shares at December 31, 2009 and 103,424,000 shares at December 31, 2008	2,825	1,034
Additional paid-in capital	1,625,035	1,372,123
Treasury stock at cost; 42,000 shares at December 31, 2009 and 36,000 shares at December 31, 2008	(268)	(540)
Accumulated deficit	(939,010)	(610,227)
Total Delta stockholders' equity	688,582	762,390
Non-controlling interest	8,538	29,104
Total equity	697,120	791,494
Total liabilities and equity	$ 1,457,485	$ 1,894,963

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Revenue:			
Oil and gas sales	$ 94,962	$ 221,733	$ 123,729
Contract drilling and trucking fees	13,680	49,445	58,358
Gain on offshore litigation settlement, net of property sales	73,800	-	-
Gain (loss) on hedging instruments, net	-	-	12,854
Total revenue	182,442	271,178	194,941
Operating expenses:			
Lease operating expense	31,303	33,508	20,882
Transportation expense	11,612	11,395	4,074
Production taxes	3,852	12,075	7,463
Exploration expense	2,604	10,975	9,062
Dry hole costs and impairments	189,072	438,963	87,459
Depreciation, depletion, amortization and accretion – oil and gas	108,505	99,125	73,875
Drilling and trucking operating expenses	15,293	32,594	37,698
Goodwill and drilling equipment impairments	6,508	29,349	-
Depreciation and amortization – drilling and trucking	22,917	14,134	16,021
General and administrative expense	41,414	53,607	49,621
Executive severance expense	3,739	-	-
Total operating expenses	436,819	735,725	306,155
Operating loss	(254,377)	(464,547)	(111,214)
Other income and (expense):			
Interest expense and financing costs	(55,035)	(45,489)	(31,899)
Interest income	2,454	10,132	2,080
Other income (expense)	1,049	(5,210)	376
Realized gain (loss) on derivative instruments, net	(1,115)	18,383	917
Unrealized gain (loss) on derivative instruments, net	(26,972)	3,365	(3,819)
Income (loss) from unconsolidated affiliates	(15,473)	3,375	(393)
Total other expense	(95,092)	(15,444)	(32,738)
Loss from continuing operations before income taxes and discontinued operations	(349,469)	(479,991)	(143,952)
Income tax expense (benefit)	215	(11,723)	5,010
Loss from continuing operations	(349,684)	(468,268)	(148,962)
Discontinued operations:			
Income from discontinued operations of properties sold or held for sale, net of tax	-	-	1,922
Gain (loss) on sale of discontinued operations, net of tax	-	718	(3,998)
Net loss	(349,684)	(467,550)	(151,038)
Less net loss attributable to non-controlling interest	20,901	11,486	1,231
Net loss attributable to Delta common stockholders	$ (328,783)	$ (456,064)	$ (149,807)
Amounts attributable to Delta common stockholders:			
Loss from continuing operations	$ (328,783)	$ (456,782)	$ (147,731)
Income (loss) from discontinued operations, net of tax	-	718	(2,076)
Net loss	$ (328,783)	$ (456,064)	$ (149,807)
Basic income (loss) attributable to Delta common stockholders per common share:			
Loss from continuing operations	$ (1.56)	$ (4.78)	$ (2.41)
Discontinued operations	-	0.01	(0.03)
Net loss	$ (1.56)	$ (4.77)	$ (2.44)
Diluted income (loss) attributable to Delta common stockholders per common share:			
Loss from continuing operations	$ (1.56)	$ (4.78)	$ (2.41)
Discontinued operations	-	0.01	(0.03)
Net loss	$ (1.56)	$ (4.77)	$ (2.44)

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, 2006	53,439	534	430,479	-	-	4,865	(4,356)	431,522	27,390	458,912	
Comprehensive income:											
Net loss	-	-	-	-	-	-	(149,807)	(149,807)	(1,231)	(151,038)	$(151,038)
Other comprehensive income transactions, net of tax											
Hedging gains reclassified to income upon settlement	-	-	-	-	-	(13,920)	-	(13,920)	-	(13,920)	(13,920)
Change in fair value of derivative hedging instruments,	-	-	-	-	-	6,025	-	6,025	-	6,025	6,025
Tax effect of valuation allowance	-	-	-	-	-	3,030	-	3,030	-	3,030	3,030
Comprehensive loss											$(155,903)
Contributions to non-controlling interests	-	-	-	-	-	-	-	-	1,137	1,137	
Shares issued for oil and gas properties	1,229	12	23,753	-	-	-	-	23,765	-	23,765	
Shares issued for cash, net of offering costs	9,898	99	196,435	-	-	-	-	196,534	-	196,534	
Shares issued for cash or return of shares upon exercise of options or vesting of restricted stock	155	3	137	-	-	-	-	140	-	140	
Issuance and amortization of non-vested stock	1,708	16	13,610	-	-	-	-	13,626	-	13,626	
Issuance of convertible debt, net of offering costs	-	-	21,621	-	-	-	-	21,621	-	21,621	
Compensation on options vested	-	-	319	-	-	-	-	319	-	319	
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	

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2009	2008 (In thousands)	2007
Cash flows from operating activities:			
Net loss	$ (349,684)	$ (467,550)	$ (151,038)
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 rig	(1,156)	-	-
Loss on sale of oil and gas properties	5,655	-	-
Loss (gain) on sale of discontinued operations	-	(718)	2,644
Depreciation, depletion, and amortization – oil and gas	108,505	99,125	73,875
Depreciation and amortization – drilling and trucking	22,917	14,134	16,021
Depreciation, depletion, and amortization – discontinued operations	-	-	2,488
Dry hole costs and impairments	189,072	438,963	86,466
Goodwill and drilling equipment impairment	6,508	29,349	-
Stock based compensation	9,695	15,638	15,590
DHS stock granted to management as compensation	266	478	245
Executive severance payable in common stock	1,700	-	-
Executive severance – stock-based awards forfeited	(2,820)	-	-
Amortization of deferred financing costs	12,151	9,316	7,049
Accretion of discount on installments payable	7,038	6,082	-
Unrealized (gain) loss on derivative contracts	26,972	(3,365)	5,816
(Gain) on marketable securities	(53)	4,590	-
(Income) loss from unconsolidated affiliates	15,809	(2,909)	393
Deferred income tax expense (benefit)	215	(11,723)	6,446
Other	(66)	61	141
Net changes in operating assets and liabilities:			
(Increase) decrease in trade accounts receivable	13,913	1,337	(4,316)
(Increase) decrease in deposits and prepaid assets	5,216	(7,381)	441
(Increase) decrease in inventories	(1,225)	(2,922)	(1,385)
(Increase) decrease in other current assets	(1,639)	(114)	713
Increase (decrease) in accounts payable	(18,924)	17,590	25,219
Increase (decrease) in offshore litigation payable	13,877	-	-
Increase (decrease) in other accrued liabilities	(702)	695	195
Net cash provided by operating activities	81,144	140,676	87,003
Cash flows from investing activities:			
Additions to property and equipment	(165,855)	(457,947)	(333,287)
Acquisitions, net of cash acquired	-	(221,815)	(4,500)
Proceeds from sale of oil and gas properties	8,393	42,000	46,193
Proceeds from sale of drilling rig and equipment	9,111	3,201	7,145
Proceeds from sale of marketable securities	2,030	-	-
Increase in restricted deposit	-	(300,000)	-
Additions to drilling and trucking equipment	(1,785)	(52,970)	(22,292)
Minority interest holder contributions (distributions), net	-	12,000	(355)
Investment in unconsolidated affiliates	295	(6,475)	(4,322)
Increase in marketable securities	-	-	(6,517)
Interest earned on long term deposit	430	-	-
Loans to affiliate	-	(490)	(8,511)
(Increase) decrease in other long-term assets	14	(120)	(106)
Net cash used in investing activities	(147,367)	(982,616)	(326,552)
Cash flows from financing activities:			
Proceeds from borrowings	100,000	375,463	228,600
Repayment of borrowings	(281,017)	(135,753)	(297,867)
Payment of deferred financing costs	(2,842)	(7,590)	(4,897)
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	202,084
Stock issued for cash upon exercise of options	-	4,827	137
Stock repurchased for withholding taxes	(380)	(1,368)	(1,381)
Proceeds from issuance of convertible debt	-	-	115,000
Net cash provided by financing activities	62,666	897,622	241,676
Net increase (decrease) in cash and cash equivalents	(3,557)	55,682	2,127
Cash at beginning of year	65,475	9,793	7,666
Cash at end of year	$ 61,918	$ 65,475	$ 9,793
Supplemental cash flow information:			
Cash paid for interest and financing costs	$ 33,937	$ 27,588	$ 23,351
Non-cash financing activities:			
Common stock issued for the purchase of Castle and oil and gas properties	$ -	$ -	$ 23,765

See accompanying notes to consolidated financial statements.

(1) Nature of Organization

Delta Petroleum Corporation ("Delta" or the "Company") was organized December 21, 1984 as a Colorado corporation and is principally engaged in acquiring, exploring, developing and producing oil and gas properties. On January 31, 2006, the Company reincorporated in the state of Delaware. The Company's core areas of operation are the Rocky Mountain and Gulf Coast Regions, which comprise the majority of its proved reserves, production and long-term growth prospects. The Company owns interests in developed and undeveloped oil and gas properties in federal units offshore California, near Santa Barbara, and developed and undeveloped oil and gas properties in the continental United States.

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, 2009, 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. The Company expects to sell or liquidate Amber during 2010.

(2) Going Concern

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

On May 13, 2009 the Company completed an underwritten public 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. The proceeds were used to reduce amounts outstanding under the Company's credit agreement and to pay accounts payable. During 2009, the Company received net proceeds of $95.8 million after contractual royalty overrides payable to third parties related to litigation with the United States government concerning offshore properties previously owned by the Company. At December 31, 2009, the Company was in compliance with its financial ratio, capital expenditures and accounts payable covenants under its credit agreement, had $39.8 million of availability under its credit agreement and had cash on hand of $61.9 million.

Despite these improvements to the financial position of the Company, during 2009 the Company experienced a net loss attributable to Delta common stockholders of $328.8 million for the year ended December 31, 2009, and at December 31, 2009 had a working capital deficiency of $79.7 million, including $83.3 million outstanding under the credit agreement of DHS Drilling Company ("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 15, 2011, which when combined with the ongoing losses and working capital deficiency, raises substantial doubt about the Company's ability to continue as a going concern.

Pursuant to a redetermination made as of October 30, 2009, the borrowing base under the Company's credit agreement was reduced to $185.0 million, of which $20.0 million of required availability must be maintained, effectively limiting the credit capacity to $165.0 million. In conjunction with the borrowing base redetermination, the Company was granted waivers of its current ratio and senior secured debt to EBITDAX ratio for the quarter ending March 31, 2010. The next scheduled borrowing base redetermination under the Company's credit agreement is currently in process and there can be no assurance that the borrowing base will not be further reduced.

(2) Going Concern, Continued

At December 31, 2009, DHS was in not in compliance with its obligation to provide to Lehman Commercial Paper, Inc. ("LCPI") by March 31 of each year audited financial statements reported on without a going concern qualification or exception by the independent auditor and DHS's previous forbearance agreement with LCPI expired on June 15, 2009. In addition, DHS was not in compliance with its various financial covenants as of December 31, 2009. Although DHS is in ongoing negotiations with 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. The DHS facility is non-recourse to Delta.

While the May 2009 public equity offering and 2009 receipt of offshore litigation proceeds have substantially funded the Company's near term liquidity needs, the Company does not have the capital on hand necessary to repay its credit facility borrowings due on January 15, 2011 or develop its properties at the pace desired based on current commodity prices. Further, in conjunction with the October 30, 2009 borrowing base redetermination, the Company is limited to capital expenditures of $10.0 million in the quarter ending March 31, 2010, and $5.0 million in the quarter ending June 30, 2010.

As a result, in November 2009, the Company retained Morgan Stanley and Evercore Partners to evaluate and advise the Board of Directors on strategic alternatives to enhance shareholder value, including but not limited to the sale of some or all of the Company's assets, entering into partnerships or joint ventures, or the sale of the entire Company. That evaluation is ongoing and it can not be assured any transaction or transactions will be proposed on terms favorable to the Company, or if proposed, completed.

In addition to the strategic evaluation process described above, the Company is working with its lenders to renegotiate the terms of the credit facility, in particular to extend the maturity date of the facility. The Company is also in discussions with other lenders in an effort to refinance the facility.

Depending on the outcome of the Company's evaluation of strategic alternatives and borrowing base redetermination currently in progress, the Company will evaluate the need to raise additional capital. There can be no assurance that the actions undertaken by the Company will be sufficient to repay the obligations under the credit agreement when due, or, if not sufficient, or if additional defaults occur, that the lenders will be willing to waive the defaults or amend the agreement. In addition, there can be no assurance that cash flow from operations and other sources of liquidity, including asset sales or joint venture or other industry partnerships, will be sufficient to meet contractual, operating and capital obligations. 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 PGR Partners, LLC ("PGR"). The Company includes its proportionate share of assets, liabilities, revenues and expenses from these entities in its consolidated financial statements. As Amber Resources Company of Colorado ("Amber") is in a net stockholders' deficit position for the periods presented, the Company has recognized 100% of Amber's losses for all periods presented. The Company does not have any off-balance sheet financing arrangements (other than operating leases) or any unconsolidated special purpose entities.

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

(3) Summary of Significant Accounting Policies, Continued

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.

During June 2007, the Company acquired a 50% non-controlling ownership interest in Delta Oilfield Tank Company, LLC ("Delta Oilfield") for cash consideration of $4.0 million. Delta Oilfield is accounted for using the equity method of accounting and is an unconsolidated affiliate of the Company. In conjunction with the investment, the Company entered into an agreement to finance up to $9.0 million for construction of a plant expansion. As of December 31, 2009, the Company had advanced $8.7 million to Delta Oilfield under this agreement, all of which is included in other long-term assets, net of reserve for bad debt, in the accompanying consolidated balance sheets. The loan is payable quarterly in an amount equal to 75% of distributable cash of Delta Oilfield, as defined, with any remaining balance due December 31, 2010.

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 properties that were held for sale during the year ended December 31, 2008 but were not subsequently sold, have been reclassified from discontinued operations to continuing operations for all periods presented. Such reclassifications had no effect on net loss.

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 2007, the Company held investments in securities that were classified as trading securities and thus recorded at estimated fair value with interest, dividend income, and changes in market value recognized in earnings. The Company recorded $334,000 of losses related to these securities during the year ended December 31, 2007. Due to the marketplace changes in late 2007 affecting the liquidity of such investments, the Company reclassified the securities from trading to available for sale as of December 31, 2007. Accordingly, the marketable securities were recorded in long term assets in the accompanying consolidated balance sheet with changes in their fair value initially recorded in accumulated other comprehensive loss. During 2008, the Company determined that the securities 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.

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 program. Since then, 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 has 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.

(3) Summary of Significant Accounting Policies, Continued

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, 2009, 2008 and 2007, respectively. Non-controlling interests for December 31, 2006 represents 50.6% (45% for Chesapeake Energy Corporation and 5.6% for DHS executive officers and management) investors of DHS at December 31, 2006. During 2007, the ownership interest of one of the founding officers was repurchased by DHS, resulting in a slight increase in Delta's ownership of DHS.

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, 2009 and 2008, 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 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.

(3) Summary of Significant Accounting Policies, Continued

Depreciation, depletion and amortization of oil and gas property and equipment for the years ended December 31, 2009, 2008 and 2007 were $108.5 million, $99.1 million, and $73.9 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.

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, 2009, the Company recorded impairments on proved properties totaling approximately $25.8 million primarily related to the Angleton, Laurel Ridge, and Opossum Hollow fields in Texas ($20.9 million), the Howard Ranch field in the Rockies ($1.5 million) and other miscellaneous fields ($3.4 million). The impairments resulted primarily from the significant decline in commodity pricing for most of 2009 which caused downward revisions to proved reserves and led to impairments.

During the year ended December 31, 2008, the Company recorded impairments on proved properties totaling approximately $236.0 million primarily related to the Newton, Midway Loop, and Opossum Hollow fields in Texas ($172.1 million), the Paradox field in Utah ($26.2 million), the Howard Ranch and Bull Canyon fields in the Rockies ($27.9 million) and the Company's offshore California field ($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 ($21.5 million) in 2008.

During the year ended December 31, 2007, an impairment of $59.4 million was recorded primarily related to the Howard Ranch and Fuller fields in Wyoming ($38.4 million and $10.3 million, respectively), and the South Angleton field in Texas ($9.7 million), primarily due to lower Rocky Mountain natural gas prices and marginally economic deep zones on the Howard Ranch Prospect.

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 $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.

(3) Summary of Significant Accounting Policies, Continued

As a result of such assessment, during the year ended December 31, 2008, the Company recorded impairments of its unproved properties totaling $66.4 million, primarily related to Utah Hingeline ($40.2 million), Opossum Hollow, Newton and Angleton in Texas ($19.2 million), certain prospects in Colorado ($4.0 million), and the Paradox basin in Utah ($3.0 million). The Company recorded no impairment provision attributable to unproved properties for the year ended December 31, 2007.

For 2010, 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 represents 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, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Asset retirement obligation – beginning of period	$ 8,737	$ 5,199	$ 4,421
Accretion expense	517	436	278
Change in estimate	465	1,883	313
Obligations incurred (from new wells)	1,908	2,579	1,743
Obligation assumed	375	-	-
Obligations settled	(564)	(1,065)	(224)
Obligations on sold properties	(899)	(296)	(1,332)
Asset retirement obligation – end of period	10,539	8,736	5,199
Less: Current asset retirement obligation	(2,885)	(2,151)	(1,045)
Long-term asset retirement obligation	$ 7,654	$ 6,585	$ 4,154

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 hedges is to provide a measure of stability to the Company's cash flows in an environment of volatile oil and gas prices. Effective July 1, 2007, the Company elected to discontinue cash flow hedge accounting on a prospective basis and recognize mark-to-market gains and losses in earnings currently instead of deferring those amounts in accumulated other comprehensive income for the contracts that qualify as cash flow hedges.

(3) Summary of Significant Accounting Policies, Continued

The Company is exposed to the fluctuations in natural gas or crude oil prices due to the nature of business in which the Company is primarily involved. In order to mitigate the risks associated with uncertain cash flows from volatile commodity prices and to provide stability and predictability in the Company's future revenues, the Company periodically enters into commodity price risk management transactions to manage its exposure to gas and oil price volatility. During the first quarter of 2009, the Company was required by the Forbearance Agreement and Amendment to the Credit Facility to execute derivative contracts to hedge anticipated oil and gas production equal to minimums of 40% for the last two quarters of 2009, 70% for the calendar year 2010 and 50% for the calendar year 2011.

At December 31, 2009, 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.

The following table summarizes the Company's open derivative contracts at December 31, 2009:

Commodity	Volume		Fixed Price	Term		Index Price	Net Fair Value Asset (Liability) at December 31, 2009 (In thousands)
Crude oil	1,000	Bbls / Day	$ 52.25	Jan '10	- Dec '10	NYMEX – WTI	(10,338)
Crude oil	500	Bbls / Day	$ 57.70	Jan '11	- Dec '11	NYMEX – WTI	(4,374)
Natural gas	6,000	MMBtu / Day	$ 5.720	Jan '10	- Dec '10	NYMEX – HHUB	(135)
Natural gas	15,000	MMBtu / Day	$ 4.105	Jan '10	- Dec '10	CIG	(6,467)
Natural gas	5,367	MMBtu / Day	$ 3.973	Jan '10	- Dec '10	CIG	(2,558)
Natural gas	12,000	MMBtu / Day	$ 5.150	Jan '11	- Dec '11	CIG	(2,352)
Natural gas	3,253	MMBtu / Day	$ 5.040	Jan '11	- Dec '11	CIG	(748)
							$(26,972)

The pre-credit risk adjusted fair value of the Company's net derivative liabilities as of December 31, 2009 was $29.5 million. A credit risk adjustment of $2.5 million to the fair value of the derivatives reduced the reported amount of the net derivative liabilities on the Company's consolidated balance sheet to $27.0 million.

(3) Summary of Significant Accounting Policies, Continued

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, 2009 (in thousands):

Derivatives Not Designated as Hedging Instruments	Balance Sheet Classification	Fair Value
Liabilities		
Commodity Swaps	Derivative Instruments – Current Liabilities, net	$ 19,497
Commodity Swaps	Derivative Instruments – Long-Term Liabilities, net	7,475
Total		$ 26,972

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, 2009 (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)	$ (1,115)
Commodity Swaps	Unrealized Loss on Derivative Instruments, net – Other Income and (Expense)	$(26,972)
		$(28,087)

Executive Severance Agreement

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 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 $4,700,000 in cash (the "Cash Consideration"), issue to him 1,000,000 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.

(3) Summary of Significant Accounting Policies, Continued

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.

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 Agreement 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.

(3) Summary of Significant Accounting Policies, Continued

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 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.

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.

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.

(3) Summary of Significant Accounting Policies, Continued

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").

Major Customers

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 accounted individually for 31% and 25%, respectively, of the Company's total oil and gas sales. During the year ended December 31, 2007, customer C and customer D individually accounted for 27% and 13%, respectively, of the Company's total oil and gas sales.

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.

Recently Adopted Accounting Standards and Pronouncements

In December 2008, the SEC approved new rules designed to modernize oil and gas reserve reporting requirements. The most significant amendments to the requirements included the following:

- Commodity Prices – Economic producibility of reserves and discounted cash flows is now based on a 12-month average commodity price unless contractual arrangements designate the price to be used.
- Disclosure of Unproved Reserves – Probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved Undeveloped Reserves Guidelines – Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years.
- Reserves Estimation Using New Technologies – Reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserves Personnel and Estimation Process – Additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Non-Traditional Resources – The definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009. The application of the new reserve rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have been used under the previous rules.

(3) Summary of Significant Accounting Policies, Continued

In addition, in January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (Update) 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the new SEC rules. The Update amends existing standards to align the reserves calculation and disclosure requirements under US GAAP with the requirements in the SEC rules. We adopted the new standards effective December 31, 2009. The new standards are applied prospectively as a change in estimate. See also Supplemental Oil and Gas Information (Unaudited).

In March 2008, the FASB issued authoritative guidance related to the accounting for convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). The guidance requires the proceeds from the issuance of convertible debt instruments to be allocated between a liability component (debt issued at a discount) and an equity component. The resulting debt discount is amortized over the period the convertible debt is expected to be outstanding as additional non-cash interest expense. This guidance was adopted on a retrospective basis effective January 1, 2009. This guidance changes the accounting treatment for the Company's 3¾% Senior Convertible Notes issued April 25, 2007 and was applied retrospectively upon adoption. The fair value of the liability and equity components was determined based on the Company's estimated borrowing rate at the date of issuance and, as a result, the liability component was approximately $92.7 million and the equity component was approximately $22.3 million. Based on these components at the issue date the Company recorded a reduction to the carrying value of the Notes of $22.3 million upon adoption of the guidance, with a corresponding increase in additional paid in capital. The accompanying consolidated financial statements include accretion of the resulting debt discount of approximately $1.1 million and $4.4 million for the three months and year ended December 31, 2009 and approximately $1.0 million and $4.2 million for the three months and year ended December 31, 2008. The remaining discount will be amortized through May 2012 when the holders of the Notes can first require the Company to purchase all or a portion of the Notes. Combined with the amortization of debt discount, the Notes have an effective interest rate of approximately 7.6% and 7.4% with total interest costs of $8.7 million and $8.5 million for the years ended December 31, 2009 and 2008, respectively.

In March 2008, the FASB issued new rules related to disclosures about derivative instruments and hedging activities which required enhanced disclosures for derivative and hedging activities. These rules were effective for the Company on January 1, 2009. The Company has included the new required disclosures in these financial statements.

In December 2007, the FASB issued new rules which established accounting and reporting standards for non-controlling interests ("minority interests") in subsidiaries. These rules clarified that a non-controlling interest in a subsidiary should be accounted for as a component of equity separate from the parent's equity. The rules were effective for the Company on January 1, 2009 and must be applied prospectively, except for the presentation and disclosure requirements, which have been applied retrospectively. The adoption of these rules had the effect of increasing total equity by the amount of the non-controlling interest and changing other presentations in the accompanying financial statements.

In April 2009, the FASB issued revised authoritative guidance requiring disclosures about fair value of financial instruments. The adoption of this guidance did not have a material impact on the Company's consolidated financial statements, other than additional disclosures. The guidance provided additional clarification for estimating fair value when the volume and level of activity for the asset or liability have significantly decreased and requires that companies provide interim and annual disclosures of the inputs and valuation technique(s) used to measure fair value. This guidance was effective for interim and annual reporting periods ending after June 15, 2009 with such disclosures included herein as applicable.

In April 2009, the FASB issued revised authoritative guidance related to interim disclosures about fair value of financial instruments. The adoption of this guidance did not have an impact on the Company's consolidated financial statements, other than requiring additional disclosures. The guidance required disclosures about fair value of financial instruments in financial statements for interim reporting periods of publicly traded companies as well as in annual

(3) Summary of Significant Accounting Policies, Continued

financial statements and was effective for interim and annual reporting periods ending after June 15, 2009. Such disclosures have been included herein as applicable.

In May 2009, the FASB issued authoritative guidance which incorporated the principles and accounting guidance for recognizing and disclosing subsequent events that originated as auditing standards into the body of authoritative literature issued by the FASB, and prescribes disclosures regarding the date through which subsequent events have been evaluated. In particular, the guidance set forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The guidance was effective for the Company beginning with the Quarterly Report on Form 10-Q for the quarter ended June 30, 2009. The implementation of this guidance did not have a material impact on the Company's financial statements. Subsequent events were evaluated through the date of issuance of these consolidated financial statements at the time this Annual Report on Form 10-K was filed with the Securities and Exchange Commission.

Recently Issued Accounting Pronouncements

Applicable recently issued accounting pronouncements have been adopted as of December 31, 2009. Please refer to "Recently Adopted Accounting Standards and Pronouncements" disclosure above for further information.

(4) Oil and Gas Properties

Unproved Undeveloped Offshore California Properties

We previously owned direct and indirect ownership interests ranging from 2.49% to 100% in five unproved undeveloped offshore California oil and gas properties. We and our 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 our offshore California properties. During 2009, we received net proceeds of $95.8 million after overrides and conveyed our leases back to the United States. Accordingly, we no longer have any remaining unproved undeveloped offshore California property interests.

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.

(4) Oil and Gas Properties, Continued

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.

Year Ended December 31, 2007 – Acquisitions/Divestitures

On October 1, 2007, the Company completed a transaction involving an exchange of Washington County, Colorado properties and cash consideration of $34.8 million, including customary purchase price adjustments, to acquire a 12.5% working interest in the Garden Gulch field in the Piceance Basin. The transaction was accounted for as a non-monetary transaction in relation to the exchange of assets with a nominal loss recorded on the divestiture of the Washington County assets equal to the fair value of the asset relinquished less its net book value. The acquisition basis of the Garden Gulch asset acquired was recorded equal to the fair value of the Washington County assets relinquished plus the additional cash consideration paid.

On June 8, 2007, the Company issued 475,000 shares of common stock valued at approximately $9.9 million using a 5-day average closing price to acquire an additional interest in one well already owned and operated by the Company, and an additional interest in a non-operated property, both located in Polk County, Texas.

On March 9, 2007, the Company issued 754,000 shares of common stock valued at approximately $13.8 million using a 5-day average closing price for additional interests in two wells already owned and operated by the Company located in Polk County, Texas.

Discontinued Operations

The results of operations and the gain (loss) relating to the sale of discontinued properties have been reflected as discontinued operations. For the year ended December 31, 2009, there were no discontinued operations and for the year ended December 31, 2008, gain on sale of discontinued operations includes a minor adjustment to the gain of $718,000 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.

The results of operations and gain (loss) relating to the sale of the following property interests have been reflected as discontinued operations under applicable FASB guidance.

On October 1, 2007, the Company completed a transaction involving an exchange of Washington County, Colorado properties and cash consideration of $34.8 million, including customary purchase price adjustments, to acquire a 12.5% working interest in the Garden Gulch field in the Piceance Basin.

On September 4, 2007, the Company completed the sale of certain non-core properties located in North Dakota for cash consideration of approximately $6.2 million. The transaction resulted in a gain on sale of properties of $4.3 million.

(4) Oil and Gas Properties, Continued

On March 30, 2007, the Company completed the sale of certain non-core properties located in New Mexico and East Texas for cash consideration of approximately $31.5 million, prior to customary purchase price adjustments. The sale resulted in a loss of approximately $10.8 million.

On March 27, 2007, the Company completed the sale of certain non-core properties located in Australia for cash consideration of approximately $6.0 million. The sale resulted in an after-tax gain of $2.0 million.

On January 10, 2007, the Company completed the sale of certain non-core properties located in Padgett field, Kansas for cash consideration of $5.6 million. The transaction resulted in a gain on sale of properties of $297,000.

The following table shows the total revenues and income included in discontinued operations for the above mentioned oil and gas properties for the year ended December 31, 2007 (in thousands):

	Year Ended December 31, 2007
Revenues	$ 6,914
Income from discontinued operations	$ 2,008
Income tax expense	(86)
Income from discontinued operations, net of tax	$ 1,922

(5) DHS Drilling Company

On December 31, 2009, the Company owned a 49.8% ownership interest in DHS Drilling Company. The remaining interest is owned by Chesapeake Energy Corporation, 47.2%, and 3% by DHS executive officers and management. Delta has the right to use all of the DHS rigs on a priority basis.

During the fourth quarter 2007, the Company acquired an additional interest for $354,000 from one of the DHS founding officers, increasing the Company's total ownership interest to 50.0% as of December 31, 2007.

On March 5, 2007, DHS purchased a drilling rig ("Rig 18") for cash consideration of $7.6 million, funded with borrowings under the DHS credit facility. The rig is a 700 horsepower rig with a depth rating of 10,500 feet.

In December 2007, DHS sold Rigs 2 and 3 for proceeds of $6.3 million and recorded a loss of $31,000 on the sale.

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 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 converted to DHS common shares in August 2008.

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.

During the quarter ended September 30, 2008, DHS paid a deposit of $1.3 million for the acquisition of a drilling rig which was expected to close in October 2008. Because of the bankruptcy of Lehman Commercial Paper and the inability of Lehman to fund DHS's credit facility, DHS was unable to close on the acquisition and the Company forfeited its deposit. Accordingly, other expense for the year ended December 31, 2008 includes the $1.3 million loss on the forfeiture of the deposit.

The Company performed the annual DHS goodwill impairment test during the quarter ended September 30, 2008; however, due to the deterioration in the market conditions and decreased utilization, the DHS goodwill and the fair values of the rigs were re-evaluated as of December 31, 2008. The Company determined that the book value of the rigs was impaired by $21.6 million and also wrote off the entire amount of goodwill of $7.7 million.

During May 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 the quarter ended June 30, 2009, DHS's efforts to market spare equipment and observations at industry auctions indicated that with industry-wide active rig counts in decline, spare equipment values had declined. As a result of these indicators of possible impairment, an analysis was performed and an impairment of $6.5 million was recorded during the second quarter of 2009 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.

(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 2009 and 2008.

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
Derivative liabilities	$ -	$ (26,972)	$ -	$ (26,972)

The following table lists the Company's fair value measurements by hierarchy as of December 31, 2008 (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, 2008
Auction rate securities	$ -	$ -	$ 1,977	$ 1,977

During 2009, the Company sold its remaining auction rate securities.

(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, and the remaining balance is due in two $100.0 million installments due November 1, 2010, and 2011. These remaining installments are 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 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 $6.1 million and $7.0 million for the years ended December 31, 2008 and 2009, 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 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 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 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, the lenders provided waivers from the December 31, 2009 and March 31, 2010 current ratio and consolidated secured debt to EBITDAX ratio covenants. In conjunction with the Second Amendment and as part of a scheduled redetermination, the borrowing base was reduced from $225.0 million to $185.0 million. The next scheduled redetermination date is March 1, 2010. Also, the Second Amendment requires that the Company maintain minimum availability of $20.0 million essentially reducing the Company's availability under the Credit Agreement. The minimum availability requirement will be released on the first date after delivery of the December 31, 2009 audited financial statements on which the Company is in compliance with its financial covenants as of the most recently completed quarter (without giving effect to any waiver of compliance with such covenants) and projects pro forma compliance for each of the four following quarters. In addition, the Second Amendment imposed capital expenditures limitations of $10.0 million for the quarter ending December 31, 2009, $10.0 million for the quarter ending March 31, 2010, and $5.0 million for the quarter ending June 30, 2010, provided that any excess of the limitation over the amount of actual expenditures may be carried forward from an earlier quarter to a subsequent quarter. The Second Amendment also included a payables covenant whereby the Company's trade payables (a sub-component of accounts payable on the accompanying consolidated balance sheet) may not exceed $30.0 million, exclusive of any amounts owed by Delta to its DHS subsidiary. The Company is currently in compliance with its financial debt covenants and based on the Company's current operating projections, the Company believes it will remain in compliance with the debt covenants. However, depending on market conditions and the possibility of further economic deterioration, the Company may need to request amendments, or waivers for the covenants, or obtain refinancing in future periods. There can be no assurance that the Company will be able to obtain amendments or waivers, or negotiate agreeable refinancing terms should it become needed.

Borrowings under the credit facility were $124.0 million at December 31, 2009, with remaining availability of $39.8 million based on the revised $185.0 million borrowing base, after allowing for reductions for the $20.0 million Availability Block and outstanding letters of credit totaling $1.2 million.

At December 31, 2009 the Company was in compliance with its accounts payable and capital expenditures limitations for the three months ended December 31, 2009. As the Company projects continuing compliance for the next year, the amounts outstanding under the credit facility have been classified as a long-term liability in the accompanying consolidated balance sheets as of December 31, 2009. However, since the facility matures in January 2011, the debt will be classified as a current liability in the Company's March 31, 2010 consolidated balance sheet, unless an extension of the facility is obtained.

(7) Long-Term Debt, Continued

Credit Facility – DHS

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 does not have any additional borrowing capacity under the LCPI facility. Under the revised agreement, DHS has 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, acceleration of all amounts due under the credit facility or foreclosure on the DHS rigs and other assets pledged as collateral, including accounts receivable. The DHS facility is non-recourse to Delta. 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 are due from Delta. 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. In addition, due to the expiration of the DHS Forbearance and the December 31, 2009 financial covenant violations, LCPI currently has the right to demand payment of the amounts outstanding under the credit facility and if not paid, foreclose on the DHS assets pledged as collateral for the credit facility. Although LCPI has not exercised its right to foreclose on the DHS assets pledged as collateral and DHS is currently in negotiations with LCPI to amend the terms of the credit facility, there can be no assurance that LCPI will not exercise its right to foreclose on the DHS assets pledged as collateral. 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,	
2010	$ 183,268
2011	224,038
2012	115,000
2013	-
2014	-
Thereafter	150,000
	$ 672,306

(8) Stockholders' Equity

Preferred Stock

The Company has 3,000,000 shares of preferred stock authorized, par value $.01 per share, issuable from time to time in one or more series. As of December 31, 2009 and 2008, 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 $.01 per share.

Common Stock

On February 9, 2007, the Company issued 1.5 million non-vested shares as executive performance share grants to the Company's four executive officers. The shares of common stock awarded will vest if the market price of Delta stock reaches and maintains certain price levels (See Note 3, "Summary of Significant Accounting Policies").

During the year ended December 31, 2007, the Company acquired oil and gas properties for 1,229,000 shares of the Company's common stock. The shares were valued at $23.7 million based on the market price of the shares at the time of issuance.

During the year ended December 31, 2007, the Company received net proceeds from public offerings of the Company's common stock of $196.7 million for 9,898,000 shares.

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 equity offering, described below. As a result, Tracinda currently owns approximately 34% of the Company's outstanding common stock

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 Agreement.

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.

(8) Stockholders' Equity, Continued

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.

A summary of the stock option activity under the Company's various plans and related information for the year ended December 31, 2009 follows:

	Year Ended December 31, 2009			
	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding-beginning of year	1,528,250	$ 8.62		
Granted	-	-		
Exercised	-	-		
Expired	(100,500)	(14.23)		
Outstanding-end of year	1,427,750	$ 8.21	3.79 years	-
Exercisable-end of year	1,427,750	$ 8.21	3.79 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, 2009 ranged from $1.87 to $15.34 per share and the weighted-average remaining contractual life of those options was 3.79 years. The Company has not issued stock options since the adoption of accounting rules which required option expense to be recorded in the statement of operations, although it has the discretion to issue options again in the future.

The total intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007 were zero, $5.3 million and $2.8 million, respectively. No options were granted during the years ended December 31, 2009, 2008 and 2007.

(8) Stockholders' Equity, Continued

A summary of the restricted stock (nonvested stock) activity under the Company's plan and related information for the year ended December 31, 2009 follows:

	Year Ended December 31, 2009			
	Nonvested Stock	Weighted-Average Grant-Date Fair Value	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Nonvested-beginning of year	2,023,112	$ 21.51		
Granted	7,762,605	1.49		
Vested	(1,632,525)	(7.80)		
Expired / Forfeit	(982,126)	(20.78)		
Nonvested-end of year	7,171,066	$ 3.06	2.33 years	$7,457,909

Stock Based Compensation

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

	Years Ended December 31,		
	2009	2008	2007
Stock options	$ -	$ -	$ 319
Non-vested stock	7,541	10,218	8,347
Performance shares	2,420	5,662	6,924
Total	$ 9,961	$ 15,880	$ 15,590

Restricted Stock - Directors and Employees

The total grant date fair value of restricted stock vested during the years ended December 31, 2009, 2008 and 2007 was $12.7 million, $6.2 million and $5.2 million, respectively.

At December 31, 2009, 2008 and 2007, the total unrecognized compensation cost related to the non-vested portion of restricted stock and stock options was $16.5 million, $22.2 million and $20.8 million which is expected to be recognized over a weighted average period of 2.33, 2.37 and 6.90 years, respectively.

Cash received from exercises under all share-based payment arrangements for the years ended December 31, 2009, 2008 and 2007, was zero, $5.1 million, and $686,000, respectively. There were no tax benefits realized from the stock options exercised during the years ended December 31, 2009, 2008 and 2007. During the years ended December 31, 2009, 2008 and 2007, zero, $8.4 million and $8.0 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, 2009, 2008 and 2007, the Company expensed $49,000, $914,000, and $590,000, 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 $165,000, $513,000 and $375,000 in 2009, 2008 and 2007, respectively. The 401(k) matching contribution was suspended in April 2009, but was subsequently reinstated on January 1, 2010.

(10) Commodity Derivative Instruments and Hedging Activities

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 to the Company's cash flows in an environment of volatile oil and gas prices. All transactions are accounted for in accordance with requirements of applicable FASB guidance. Effective July 1, 2007, the Company elected to discontinue cash flow hedge accounting on a prospective basis. Beginning July 1, 2007, the Company recognizes mark-to-market gains and losses in current earnings instead of deferring those amounts in accumulated other comprehensive income. As a result of the Company's election to discontinue hedge accounting, the amount recorded in accumulated other comprehensive income for hedges that were effective as of June 30, 2007 was fixed until the period those derivatives were settled, with all subsequent changes in fair value recorded in gain (loss) from ineffective derivative contracts. All amounts in accumulated other comprehensive income as of June 30, 2007 were reclassified to gain (loss) on effective derivative contracts as of December 31, 2007, as all such derivatives had settled.

At December 31, 2008, the Company did not have any outstanding derivative contracts. During late third quarter and early fourth quarter 2008, the Company cash settled the majority of its then outstanding derivative contracts in order to reduce counterparty credit risk. Contracts that were not terminated early settled in accordance with their original terms by December 31, 2008.

The following table summarizes our open derivative contracts at December 31, 2009:

Commodity	Volume		Fixed Price	Term		Index Price	Net Fair Value Asset (Liability) at December 31, 2009 (In thousands)
Crude oil	1,000	Bbls / Day	$ 52.25	Jan '10	- Dec '10	NYMEX – WTI	(10,338)
Crude oil	500	Bbls / Day	$ 57.70	Jan '11	- Dec '11	NYMEX – WTI	(4,374)
Natural gas	6,000	MMBtu / Day	$ 5.720	Jan '10	- Dec '10	NYMEX – HHUB	(135)
Natural gas	15,000	MMBtu / Day	$ 4.105	Jan '10	- Dec '10	CIG	(6,467)
Natural gas	5,367	MMBtu / Day	$ 3.973	Jan '10	- Dec '10	CIG	(2,558)
Natural gas	12,000	MMBtu / Day	$ 5.150	Jan '11	- Dec '11	CIG	(2,352)
Natural gas	3,253	MMBtu / Day	$ 5.040	Jan '11	- Dec '11	CIG	(748)
							$(26,972)

The net gains (losses) from all hedging activities recognized in the Company's statements of operations were ($28.1 million), $21.7 million, and $10.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

(11) Income Taxes

Income tax expense (benefit) attributable to income from continuing operations consisted of the following for the years ended December 31, 2009, 2008 and 2007:

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Current:			
U.S. - Federal	$ -	$ -	$ 47
U.S. - State	-	-	(5)
Foreign	-	66	-
Deferred:			
U.S. - Federal	190	(11,235)	4,653
U.S. - State	25	(554)	315
Foreign	-	-	-
	$ 215	$ (11,723)	$ 5,010

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,		
	2009	2008	2007
Federal statutory rate	(35.0)%	(35.0)%	(35.0)%
State income taxes, net of federal benefit	(1.9)	(1.9)	(2.1)
Change in valuation allowance	35.3	34.7	40.6
Other	0.8	(0.3)	0.1
Actual income tax rate	(0.8)%	(2.5)%	3.6%

(11) Income Taxes, Continued

Deferred tax assets (liabilities) are comprised of the following at December 31, 2009 and 2008 (in thousands):

	2009	2008
Deferred tax assets:		
Net operating loss	$ 258,496	$ 136,934
Asset retirement obligation	4,242	3,218
Percentage depletion	597	592
Property and equipment	89,441	81,837
Equity compensation	7,823	10,800
Marketable securities	120	1,690
Equity investments	1,751	421
Derivative instruments	10,019	478
Minimum tax credit	1,221	1,221
Contribution carryforwards	512	-
Accrued bonuses	-	116
Allowance for doubtful accounts	38	234
Accrued vacation liability	173	287
Other	6	481
Total deferred tax assets	374,439	238,309
Valuation allowance	(354,652)	(219,163)
Net deferred tax assets	$ 19,787	$ 19,146
Deferred tax liabilities:		
Property and equipment	(19,390)	(19,625)
Prepaid insurance and other	(397)	(314)
Total deferred tax liabilities	$ (19,787)	$ (19,939)

The Company has net operating loss carryovers as of December 31, 2009 of $738.1 million for federal income tax purposes and $701.9 million for financial reporting purposes. The difference of $36.2 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.

(11) Income Taxes, Continued

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, 2009, and projections of 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 conclude, that the Company does not meet the "more likely than not" requirement in order to recognize deferred tax assets. Accordingly, for the year ended December 31, 2009, the Company recorded an income tax expense valuation allowance of $354.7 million offsetting the Company's deferred tax assets.

At December 31, 2009, the Company had net operating loss carryforwards for regular and alternative minimum tax purposes as follows:

Regular tax net operating loss carryforwards	$ 738,080
Alternative minimum tax net operating loss carryforwards	715,946

If not utilized, the tax net operating loss carryforwards will expire from 2009 through 2028.

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

2010	$ 6,004
2011	5,939
2012	994
2013	868
2014	3,132
2015 and thereafter	721,143
	$738,080

In August 2007, the Company experienced cumulative ownership changes as defined by the Internal Revenue Code ("IRC") 382 and as a result, a portion of the Company's net operating loss utilization after the change date will be subject to IRC 382 limitations of approximately $45.0 million annually for federal income taxes. Further, a portion of the Company's net operating losses generated in 2008 and 2009 may be subject to IRC 382 limitations.

Effective January 1, 2007, the Company adopted applicable provisions of FASB Interpretation to recognize, measure and disclose of uncertain tax positions in the financial statements. Under the applicable FASB Interpretation, 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. Upon the adoption of the new accounting provision, the Company had no unrecognized tax benefits. During the year ended December 31, 2009, 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 at December 31, 2009.

The tax years 2006 through 2008 for federal returns and 2005 through 2008 for state returns remain open to examination by the major taxing jurisdictions in which we operate, although no material changes to unrecognized tax positions are expected within the next year.

(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 $67,000, $154,000, and $110,000, for their respective 1% ORRI during the years ended December 31, 2009, 2008 and 2007, 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 "LEGAL PROCEEDINGS"), 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.

Accounts Receivable Related Parties

At December 31, 2009 and 2008, the Company had $15,000 and $331,000 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,		
	2009	2008	2007
Net income (loss) attributable to Delta common stockholders	$(328,783)	$ (456,064)	$(149,807)
Basic weighted-average shares outstanding	211,033	95,530	61,297
Add: dilutive effects of stock options and unvested stock grants	-	-	-
Diluted weighted-average common shares outstanding	211,033	95,530	61,297
Basic net income (loss) per common share	$ (1.56)	$ (4.77)	$ (2.44)
Diluted net income (loss) per common share	$ (1.56)	$ (4.77)	$ (2.44)

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

	Years Ended December 31,		
	2009	2008	2007
Stock issuable upon conversion of convertible notes	3,790	3,790	3,790
Stock options	1,427	1,528	2,157
Non-vested restricted stock	7,171	2,023	2,115
Total potentially dilutive securities	12,388	7,341	8,062

(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, 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, 2009, and 2008, the condensed consolidated statements of operations for the years ended December 31, 2009, 2008 and 2007, and the condensed consolidated statements of cash flows for the years ended December 31, 2009, 2008 and 2007 (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, 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	$ 165,867	$ (2,666)	$ 22,225	$ (2,984)	$ 182,442
Operating expenses:					
Oil and gas expense	42,828	214	3,725	-	46,767
Exploration expense	2,604	-	-	-	2,604
Dry hole costs and impairments	187,176	1,896	6,508	-	195,580
Depreciation and depletion	95,333	253	36,415	(579)	131,422
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	368,795	2,438	67,987	(2,401)	436,819
Operating loss	(202,928)	(5,104)	(45,762)	(583)	(254,377)
Other expenses	(87,202)	(33)	(7,857)	-	(95,092)
Income tax (expense) benefit	(1,009)	-	794	-	(215)
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	(153,980)	2,659	3,954	(147,367)
Financing activities	73,162	-	(10,496)	62,666
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 Balance Sheet
December 31, 2008

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 167,536	$ 591	$ 54,630	$ -	$ 222,757
Property and equipment:					
Oil and gas properties	1,681,804	503	110,650	(11,944)	1,781,013
Drilling rigs and trucks	594	-	193,629	-	194,223
Other	76,932	36,359	1,892	-	115,183
Total property and equipment	1,759,330	36,862	306,171	(11,944)	2,090,419
Accumulated depletion, depreciation and amortization	(544,154)	(21,896)	(92,229)	-	(658,279)
Net property and equipment	1,215,176	14,966	213,942	(11,944)	1,432,140
Investment in subsidiaries	141,827	-	-	(141,827)	-
Other long-term assets	235,560	3,825	681	-	240,066
Total assets	$ 1,760,099	$ 19,382	$ 269,253	$(153,771)	$1,894,963
Current liabilities	$ 550,876	$ 172	$ 13,480	$ -	$ 564,528
Long-term liabilities					
Long-term debt, derivative instruments and deferred taxes	435,684	1,800	94,872	-	532,356
Asset retirement obligation and other liabilities	6,307	10	268	-	6,585
Total long-term liabilities	441,991	1,810	95,140	-	538,941
Total Delta stockholders' equity	738,128	17,400	160,633	(153,771)	762,390
Non-controlling interest	29,104	-	-	-	29,104
Total equity	767,232	17,400	160,633	(153,771)	791,494
Total liabilities and equity	$ 1,760,099	$ 19,382	$269,253	$(153,771)	$1,894,963

(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	$ 208,978	$ 721	$ 112,553	$ (51,074)	$ 271,178
Operating expenses:					
Oil and gas expense	53,652	130	3,196	-	56,978
Exploration expense	10,975	-	-	-	10,975
Dry hole costs and impairments	417,494	21,469	29,349	-	468,312
Depreciation and depletion	93,287	307	28,967	(9,302)	113,259
Drilling and trucking operating expenses	-	-	62,422	(29,828)	32,594
General and administrative	48,145	71	5,391	-	53,607
Total operating expenses	623,553	21,977	129,325	(39,130)	735,725
Operating loss	(414,575)	(21,256)	(16,772)	(11,944)	(464,547)
Other income and expenses	(16,267)	40	(11,077)	11,860	(15,444)
Income tax benefit	3,580	-	8,143	-	11,723
Discontinued operations	718	-	-	-	718
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

(14) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Operations
Year Ended December 31, 2007

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 131,905	$ 577	$ 95,288	$ (32,829)	$ 194,941
Operating expenses:					
Oil and gas expense	31,241	118	1,060	-	32,419
Exploration expense	9,062	-	-	-	9,062
Dry hole costs and impairments	85,084	-	-	2,375	87,459
Depreciation and depletion	69,963	11	25,953	(6,031)	89,896
Drilling and trucking operating expenses	-	-	59,720	(22,022)	37,698
General and administrative	44,543	(1)	5,079	-	49,621
Total operating expenses	239,893	128	91,812	(25,678)	306,155
Operating income (loss)	(107,988)	449	3,476	(7,151)	(111,214)
Other income and expenses	(25,351)	88	(8,705)	1,230	(32,738)
Income tax (expense) benefit	(4,486)	-	1,809	(2,333)	(5,010)
Discontinued operations	(2,076)	-	-	-	(2,076)
Net income (loss)	(139,901)	537	(3,420)	(8,254)	(151,038)
Less loss attributable to non-controlling interest	1,231	-	-	-	1,231
Net income (loss) attributable to Delta common stockholders	$(138,670)	$ 537	$ (3,420)	$ (8,254)	$(149,807)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2007

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Cash provided by (used in):				
Operating activities	$ 70,280	$ 208	$ 16,515	$ 87,003
Investing activities	(286,428)	(1,538)	(38,586)	(326,552)
Financing activities	218,523	-	23,153	241,676
Net increase (decrease) in cash and cash equivalents	2,375	(1,330)	1,082	2,127
Cash at beginning of the period	2,282	1,637	3,747	7,666
Cash at the end of the period	$ 4,657	$ 307	$ 4,829	$ 9,793

(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, 2009, 2008 and 2007, was approximately $1,667,000, $1,596,000, and $1,150,000, respectively. The following table summarizes the future minimum payments under all non-cancelable operating lease obligations (in thousands):

2010	$ 2,447
2011	1,570
2012	1,422
2013	1,431
2014	1,490
2015 and thereafter	946
	$ 9,306

On April 30, 2007, the Company entered into agreements with four 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 replaced similar agreements that expired on December 31, 2006.

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 our 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 million, which resulted in net proceeds to it of approximately $50 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.

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 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.

(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, 2009, 2008 and 2007.

	Oil and Gas	Drilling	Inter-segment Eliminations	Consolidated
		(In thousands)		
Year Ended December 31, 2009				
Revenues from external customers	$ 168,762	$ 13,680	$ -	$ 182,442
Inter-segment revenues	-	2,984	(2,984)	-
Total revenues	168,762	16,664	(2,984)	182,442
Operating loss	(219,210)	(34,584)	(583)	(254,377)
Other income and (expense) [1]	(87,229)	(7,863)	-	(95,092)
Loss from continuing operations, before tax	$(306,439)	$(42,447)	$ (583)	$(349,469)
Year Ended December 31, 2008				
Revenues from external customers	$ 221,733	$ 49,445	$ -	$ 271,178
Inter-segment revenues	-	51,074	(51,074)	-
Total revenues	221,733	100,519	(51,074)	271,178
Operating loss	(432,650)	(19,953)	(11,944)	(464,547)
Other income and (expense) [1]	(16,221)	(11,083)	11,860	(15,444)
Loss from continuing operations, before tax	$(448,871)	$(31,036)	$ (84)	$(479,991)
Year Ended December 31, 2007				
Revenues from external customers	$ 136,583	$ 58,358	$ -	$ 194,941
Inter-segment revenues	-	34,410	(34,410)	-
Total revenues	136,583	92,768	(34,410)	194,941
Operating income (loss)	(108,501)	8,931	(11,644)	(111,214)
Other income and (expense) [1]	(25,264)	(8,705)	1,231	(32,738)
Income (loss) from continuing operations, before tax	$(133,765)	$ 226	$(10,413)	$(143,952)
December 31, 2009				
Total Assets	$1,419,754	$ 104,287	$(66,556)	$1,457,485
December 31, 2008				
Total Assets	$1,797,683	$ 163,240	$(65,960)	$1,894,963

[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, 2009				
Total revenue	$ 58,656	$ 22,942	$ 23,922	$ 76,922
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	(30,017)	(180,218)	(100,708)	(38,526)
Net income (loss)	(25,554)	(172,318)	(96,827)	(34,084)
Net income (loss) per common share: (1)				
Basic	$ (.25)	$ (.89)	$ (.35)	$ (0.12)
Diluted	$ (.25)	$ (.89)	$ (.35)	$ (0.12)
Year Ended December 31, 2008				
Total revenue	$ 64,480	$ 81,107	$ 72,048	$ 53,543
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	(21,730)	(24,110)	45,763	(479,914)
Net income (loss)	(20,782)	(23,387)	48,800	(460,693)
Net income (loss) per common share: (1)				
Basic	$ (.26)	$ (.23)	$ .48	$ (4.55)
Diluted	$ (.26)	$ (.23)	$ .45	$ (4.55)

(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 and Major Customers (Unaudited)

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

	December 31, 2009	December 31, 2008	December 31, 2007
Unproved properties	$ 280,844	$ 415,573	$ 247,466
Proved properties	1,379,920	1,365,440	749,393
	1,660,764	1,781,013	996,859
Accumulated depreciation and depletion	(661,851)	(548,618)	(204,014)
	$ 998,913	$ 1,232,395	$ 792,845

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

	December 31, 2009	December 31, 2008	December 31, 2007
Unproved property acquisition costs	$ 2,083	$ 180,149	$ 28,713
Proved property acquisition costs	-	41,666	46,158
Development costs incurred on proved undeveloped reserves	15,556	123,999	144,156
Development costs - other	43,892	261,588	119,607
Exploration and dry hole costs	36,216	122,827	35,735
	$ 97,747	$ 730,229	$ 374,369

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,		
	2009	2008	2007
Balance at beginning of year	$ 13,812	$ 44,091	$ 27,453
Additions to capitalized exploratory well costs pending the determination of proved reserves	-	12,397	30,797
Exploratory well costs included in property divestitures	-	(1,677)	(2,941)
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)	(11,218)
Balance at end of year	$ -	$ 13,812	$ 44,091
Exploratory well costs capitalized for one year or less after after completion of drilling	-	13,812	35,649
Exploratory well costs capitalized for greater than one year after completion of drilling	-	-	8,442
Balance at end of year	$ -	$ 13,812	$ 44,091

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

Included in capitalized exploratory well costs capitalized for greater than one year after completion of drilling at December 31, 2007 were two projects. One project representing $1.7 million of the costs was non-operated and pending connection to a new field gathering system. During 2008, the field that included the project was sold. The second project representing $6.8 million of the costs capitalized for greater than one year after completion of drilling at December 31, 2007 was related to the Company's Paradox Basin properties. During 2008, substantial additional work was performed, but in the fourth quarter of 2008, as a result of drilling results and the decline in commodity prices, the costs were charged to dry hole expense. During 2009, the Company declared its exploratory Columbia River Basin well a dry hole and accordingly, at December 31, 2009, the Company has no remaining capitalized exploratory well costs.

(18) Disclosures About Capitalized Costs, Costs Incurred and Major Customers (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,		
	2009	2008	2007
Revenue:			
Oil and gas revenues	$ 94,962	$ 221,733	$ 123,729
Expenses:			
Production costs	46,767	56,978	32,419
Depletion and amortization	105,426	96,490	71,867
Exploration	2,604	10,975	9,062
Abandoned and impaired properties	155,460	327,112	58,411
Dry hole costs	33,612	111,851	29,048
Results of operations of oil and gas producing activities	$ (248,907)	$ (381,673)	$ (77,078)
Income from operations of properties sold, net	-	-	1,922
Gain (loss) on sale of properties	-	-	(3,998)
Results of discontinued operations of oil and gas producing activities	$ -	$ -	$ (2,076)

(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. See Note 3, "Summary of Significant Accounting Policies – Recently Adopted Standards and Pronouncements." We adopted the rules effective December 31, 2009 and the rule changes, including those related to pricing and technology, are included in our reserves estimates.

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. See Note 3, "Summary of Significant Accounting Policies – Recently Adopted Standards and Pronouncements."

Application of the new rules resulted in the use of lower prices at December 31, 2009 for both oil and gas than would have been used under the previous rules.

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 year ended December 31, 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 estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

Estimates of the Company's oil and natural gas reserves and present values as of December 31, 2009, December 31, 2008, and December 31, 2007 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, 2009, 2008, and 2007 is as follows (in thousands):

	Gas (MMcf)	Oil (MBbl)	Total (MMcfe)
Estimated Proved Reserves: Balance at December 31, 2006	224,704	12,947	302,386
Revisions of quantity estimate [(1)]	23,932	(2,101)	11,326
Extensions and discoveries [(2)]	86,269	2,423	100,807
Purchase of properties [(3)]	10,559	266	12,155
Sale of properties [(4)]	(24,738)	(1,425)	(33,288)
Production	(11,253)	(1,085)	(17,763)
Estimated Proved Reserves: Balance at December 31, 2007	309,473	11,025	375,623
Revisions of quantity estimate [(5)]	191,002	(4,108)	166,354
Extensions and discoveries [(6)]	152,801	1,652	162,713
Purchase of properties [(7)]	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 [(8)]	(701,626)	(3,985)	(725,536)
Extensions and discoveries [(9)]	19,607	129	20,381
Purchase of properties	-	-	-
Sale of properties [(10)]	(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
Proved developed reserves:			
December 31, 2007	92,194	4,548	119,482
December 31, 2008	161,552	3,274	181,196
December 31, 2009	115,004	2,977	132,866
Proved undeveloped reserves:			
December 31, 2007	217,279	6,477	256,141
December 31, 2008	666,125	6,179	703,199
December 31, 2009	11,688	1,505	20,719

Base Pricing, before adjustments for contractual differentials:

	CIG per Mmbtu	WTI per Bbl
December 31, 2007	$5.88	$95.98
December 31, 2008	$4.51	$44.60
December 31, 2009	$3.03	$61.18

Proved reserves were required to be calculated based on single day end of period prices for the years ended December 31, 2007 and 2008. For 2009, 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 2007 positive gas revisions were primarily related to longer lived Piceance Basin wells due to higher gas pricing at year-end 2007. Downward performance revisions in the Company's Gulf Coast Austin Chalk completions dominated the liquids change.

(2) The 2007 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 2007, the Company purchased incremental interests in its existing Piceance Basin acreage and in its existing Gulf Coast Austin Chalk acreage.

(4) During 2007, proved reserves located in various states were sold in a series of transactions described in Note 4, "Oil and Gas Properties – Discontinued Operations."

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

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

(6) 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.

(7) 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.

(8) 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.

(9) 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.

(10) 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."

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.

	2009	2008	2007
		(in thousands)	
Future net cash flows	$ 662,029	$ 3,542,332	$ 2,951,481
Future costs:			
Production	125,108	924,705	735,610
Development and abandonment	77,965	1,337,842	585,622
Income taxes[1]	-	-	226,354
Future net cash flows	458,956	1,279,785	1,403,895
10% discount factor	(302,272)	(1,120,417)	(702,021)
Standardized measure of discounted future net cash flows	$ 156,684	$ 159,368	$ 701,874
Estimated future development cost anticipated for following two years on existing properties	$ 59,313	$ 216,293	$ 334,326

[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 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, 2009, 2008 and 2007 are as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Beginning of the year	$ 159,368	$ 701,874	$ 483,234
Sales of oil and gas production during the period, net of production costs	(48,195)	(164,755)	(95,976)
Purchase of reserves in place	-	289,040	38,364
Net change in prices and production costs	(64,282)	(907,844)	286,255
Changes in estimated future development costs	741,318	(27,087)	(106,678)
Extensions, discoveries and improved recovery	17,509	242,079	135,868
Revisions of previous quantity estimates, estimated timing of development and other	(674,560)	(281,302)	(83,240)
Previously estimated development and abandonment costs incurred during the period	15,556	123,999	144,156
Sales of reserves in place	(5,967)	-	(77,631)
Change in future income tax	-	113,177	(70,801)
Accretion of discount	15,937	70,187	48,323
End of year	$ 156,684	$ 159,368	$ 701,874

(20) Subsequent Event

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 sold 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 will most likely 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.

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Glossary of Oil and Gas Terms

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

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.

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

MBbls. Thousands of barrels.

Mcf. Thousand cubic feet (of natural gas).

Mcfe. Thousand cubic feet equivalent.

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

MMcf. Million cubic feet.

MMcfe. Million cubic feet equivalent.

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 11th day of March, 2010.

DELTA PETROLEUM CORPORATION

By: /s/ John R. Wallace
John R. Wallace, President and Chief Operating 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 11, 2010
/s/ Kevin R. Collins Kevin R. Collins, Director	March 11, 2010
/s/ Jerrie F. Eckelberger Jerrie F. Eckelberger, Director	March 11, 2010
/s/ Jean-Michel Fonck Jean-Michel Fonck, Director	March 11, 2010
/s/ Aleron H. Larson, Jr. Aleron H. Larson, Jr., Director	March 11, 2010
/s/ Russell S. Lewis Russell S. Lewis, Director	March 11, 2010
/s/ Anthony Mandekic Anthony Mandekic, Director	March 11, 2010
/s/ James J. Murren James J. Murren, Director	March 11, 2010
/s/ Jordan R. Smith Jordan R. Smith, Director	March 11, 2010
/s/ Daniel J. Taylor Daniel J. Taylor, Director	March 11, 2010
/s/ John R. Wallace John R. Wallace, Director	March 11, 2010

STOCK PERFORMANCE GRAPH

The performance graph shown below was prepared using data prepared by Standard and Poor's Investment Services. As required by applicable rules of the SEC, the graph was prepared based upon the following assumptions:

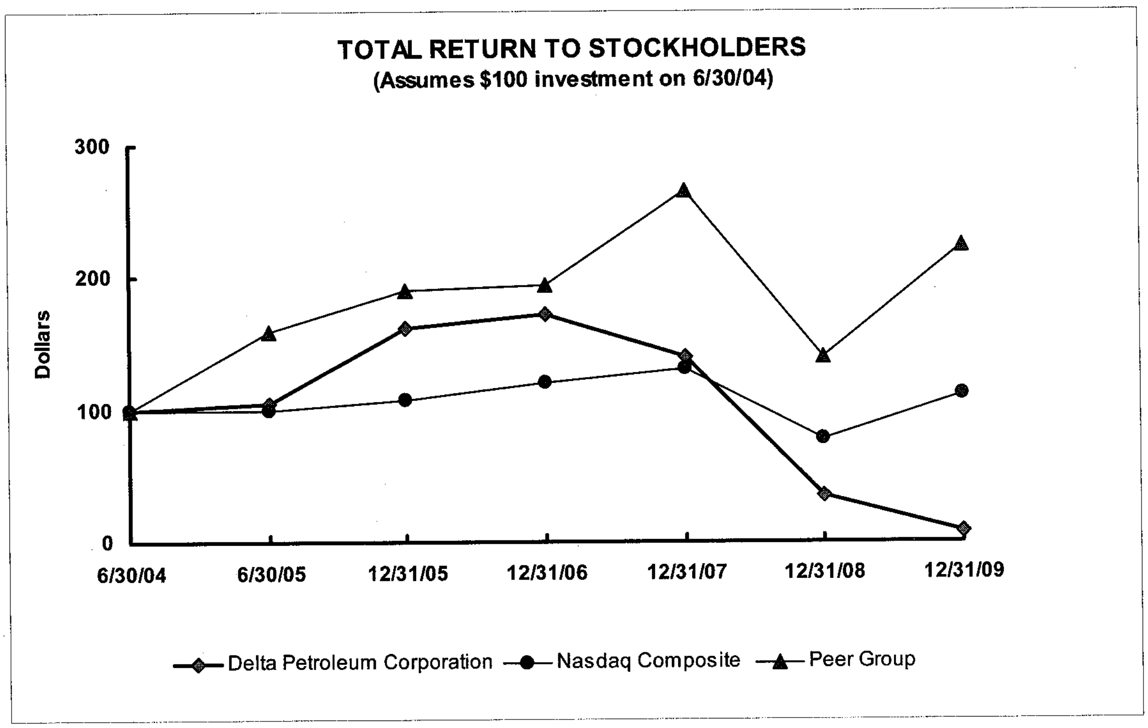
1. $100 was invested in Delta Common Stock, the Nasdaq Composite Index (U.S.) and the Peer Group (as defined below) on June 30, 2004.

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 Corp., St. Mary Land & Exploration Co., and Whiting Petroleum Corp. Edge Petroleum Corp., which was previously part of the Peer Group, is no longer included because it ceased operations during 2009.

COMPARATIVE CUMULATIVE TOTAL RETURNS
DELTA PETROLEUM CORPORATION
NASDAQ COMPOSITE INDEX AND PEER GROUP
(Performance results through December 31, 2009)



Total Return Analysis							
	6/30/04	6/30/05	12/31/05	12/31/06	12/31/07	12/31/08	12/31/09
Delta Petroleum Corp.	$100.00	$104.98	$161.86	$172.19	$140.15	$35.39	$7.73
Nasdaq Composite	$100.00	$99.83	$107.13	$120.53	$130.79	$77.30	$111.65
Peer Group	$100.00	$159.60	$189.89	$194.25	$264.54	$140.22	$223.80

Officers and Directors

John R. Wallace
President, COO 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

DPTR
NASDAQ
GLOBAL SELECT

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 May 25, 2010 at Delta's offices, 370 17th Street, Suite 4300, Denver, CO 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 info@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, 2009 and subsequent reports on Forms 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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