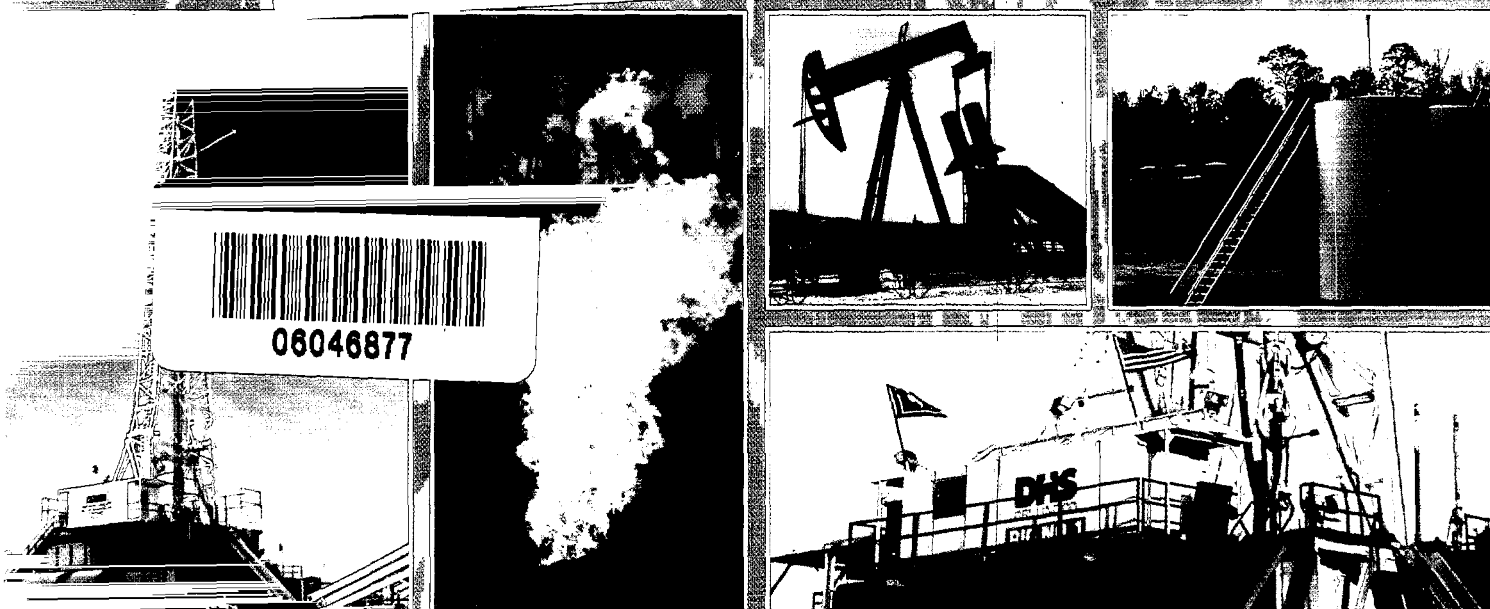
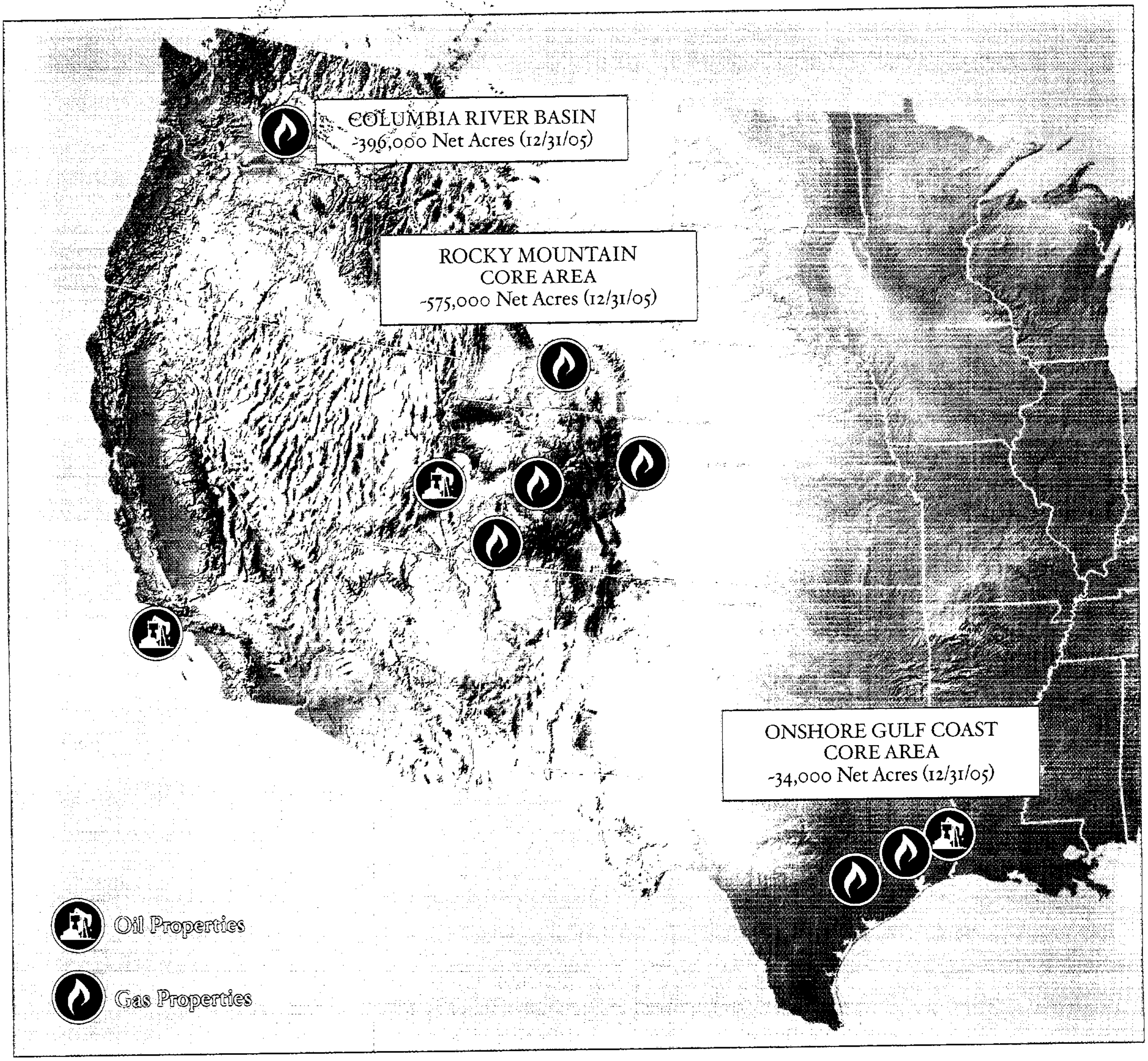


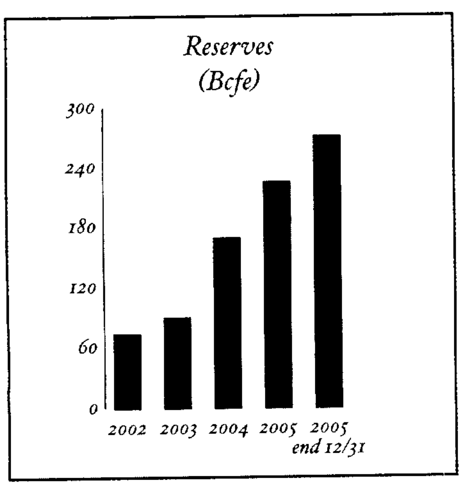
DELTA PETROLEUM CORPORATION

2005 transition period report
six months ended December 31, 2005

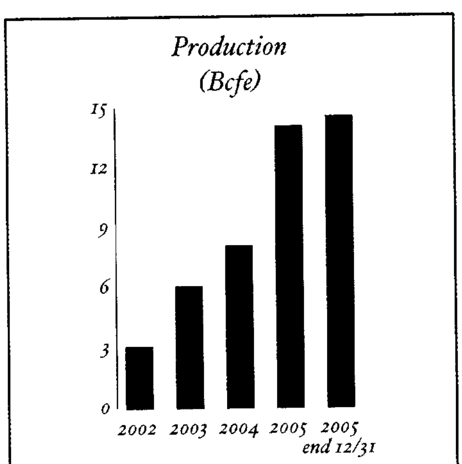
OPERATIONS



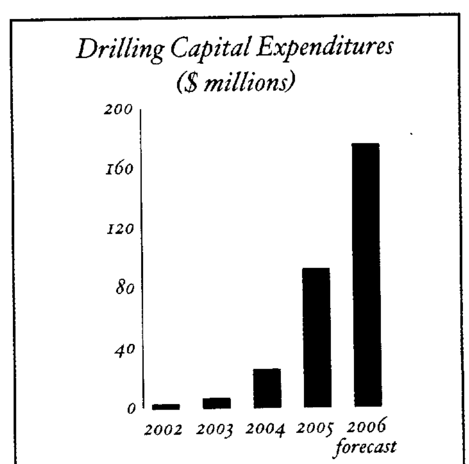
COLUMBIA RIVER BASIN
~396,000 Net Acres (12/31/05)
ROCKY MOUNTAIN
CORE AREA
~575,000 Net Acres (12/31/05)
ONSHORE GULF COAST
CORE AREA
~34,000 Net Acres (12/31/05)
Oil Properties
Gas Properties



Reserves
(Bcfe)
300
240
180
120
60
0
2002
2003
2004
2005
2005
end 12/31



Production
(Bcfe)
15
12
9
6
3
0
2002
2003
2004
2005
2005
end 12/31

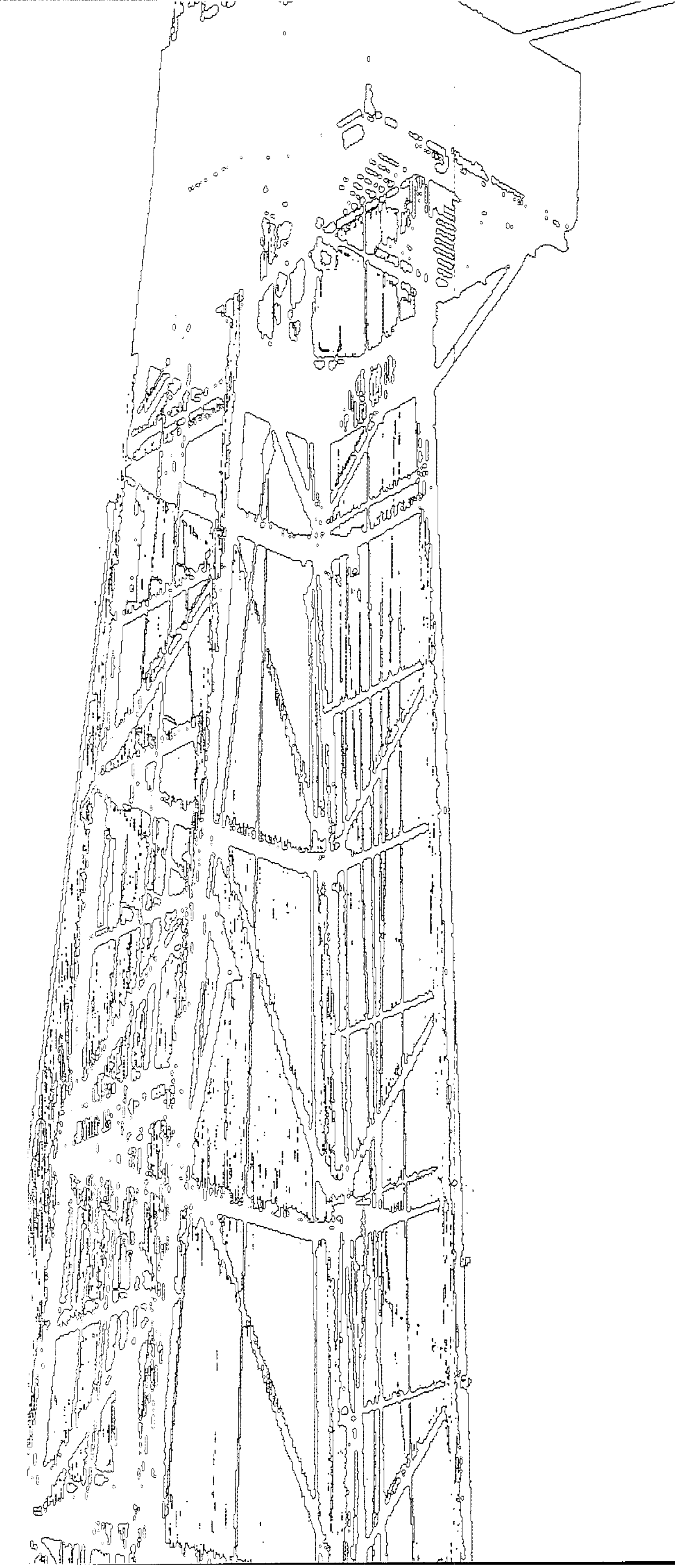


Drilling Capital Expenditures
($ millions)
200
160
120
80
40
0
2002
2003
2004
2005
2006
forecast

FINANCIAL AND OPERATING DATA

Financial Results (In thousands except per share amounts)	*6 Months Ended December 31,* 2005	2004	*Years Ended June 30,* 2005	2004
Total Revenue	$ 61,774	$ 39,864	$ 94,707	$ 36,367
Operating Expenses	$ 64,024	$ 29,769	$ 75,998	$ 32,500
Operating Income	$ (2,250)	$ 10,095	$ 18,709	$ 3,867
Other Income (Expense)	$ (18,268)	$ (2,070)	$ (7,433)	$ (1,570)
Income (Loss) from Continuing Operations	$ (20,518)	$ 8,025	$ 11,276	$ 2,297
Income Tax Expense (Benefit)	$ 7,639	$ –	$ (3,325)	$ –
Net Earnings (Loss) from Continuing Operations	$ (12,879)	$ 8,025	$ 14,601	$ 2,297
Net Income	$ (590)	$ 8,754	$ 15,050	$ 5,056
Net Income Per Share-Basic	$ (.01)	$ .22	$ 0.37	$ 0.19
Net Income Per Share-Diluted	$ (.01)	$ .21	$ 0.36	$ 0.17
Current Assets	$ 61,589	$ 21,133	$ 27,034	$ 14,953
Net Property and Equipment	$ 621,154	$ 303,362	$ 473,550	$ 256,339
Total Long Term Assets	$ 10,650	$ 1,605	$ 12,399	$ 1,412
Total Assets	$ 693,393	$ 326,100	$ 512,983	$ 272,704
Current Liabilities	$ 106,772	$ 23,619	$ 54,150	$ 14,290
Long-Term Debt	$ 241,659	$ 83,236	$ 216,001	$ 69,630
Other Liabilities	$ 9,011	$ 273	$ 6,595	$ 2,542
Stockholders' Equity	$ 320,455	$ 216,284	$ 221,623	$ 185,997
Total Liabilities and Stockholders' Equity	$ 693,393	$ 326,100	$ 512,983	$ 272,704

Oil and Gas Reserves and Operations	*6 Months Ended December 31,* 2005	2004	*Years Ended June 30,* 2005	2004
Proved Reserves:				
Oil, Condensate and NGL's (MBbls)	14,709		13,866	13,205
Natural Gas (MMcf)	181,154		141,041	88,479
Natural Gas Equivalents (MMcfe)	269,408		224,237	167,709
Percent Developed	39%		52%	58%
SEC PV-10 After Tax (000)	$ 749,624		$ 517,370	$ 288,037
Finding Cost ($/Mcfe, all inclusive)	$ 2.43		$ 2.81	$ 2.03
Annual Production:				
Oil, Condensate and NGL's (MBbls)	509	523	1,055	748
Natural Gas (MMcf)	3,720	3,297	7,675	3,110
Natural Gas Equivalents (MMcfe)	6,774	6,435	14,005	7,598
Reserve/Production Ratio (Years)	NM	NM	16.0	22.1
Production Replacement %	NM	NM	565%	1264%



DEAR SHAREHOLDERS

The six-month transition period that ended December 31, 2005 marked another important milestone for the Company. Today Delta has a solid platform of producing properties, a large inventory of low-risk development opportunities and a sizeable leasehold position in two major projects that have significant reserve potential. In addition, we have continued to grow our drilling rig subsidiary, DHS Drilling Company, to a current fleet of 16 rigs. This combination of assets should allow for sustainable growth.

In the 13 months since our last full fiscal year-end on June 30, 2005 we have achieved a number of accomplishments that will allow us to execute our business plan and deliver steady and meaningful production and reserve growth for the foreseeable future. This includes the following:

- Completed a 58-square-mile 3D seismic survey around the Company's Newton Field in southeastern Texas, which has identified the probable existence of meaningful additional reserves. The first well on a new geologic feature was drilled deeper and found the same upper Wilcox formation sands that define the Newton Field production and an apparent deeper middle Wilcox formation discovery.

- In the Piceance Basin in western Colorado, we acquired an interest in the Garden Gulch Field and added approximately 1,000 net acres of leasehold to our Vega Unit development project. Since June 30, 2005, 14 wells have been drilled in Vega and 22 wells have been drilled in Garden Gulch. Both areas will experience continuous development drilling for many years.

- Tripled our leasehold ownership in the Columbia River Basin in Washington to approximately 396,000 net acres at December 31, 2005. There are currently two new wells being drilled on separate geologic structures, the first of which has reached total depth and will begin completion activity relatively soon. The second well is expected to reach total depth this fall. In addition, we have initiated the permitting process for two wells that we may drill on separate 100% owned geologic structures in 2007.

- Acquired approximately 170,000 gross acres (110,000 net) in the central Utah overthrust (Hingeline) project where we have identified 21 geologic structures, the first of which we plan to drill in the third quarter.

- Acquired approximately 37,000 additional gross acres (19,000 net) leasehold in the Paradox Basin in Utah and Colorado where we now have approximately 88,000 gross acres (52,000 net) on five distinct geologic structural features. We have drilled two exploratory tests with apparent success and have begun completion activity.

- Drilled two successful Austin Chalk wells in our Midway Loop project in Polk and Tyler Counties, Texas in what is expected to be a 14-well program.

- Drilled a successful deep Sligo exploratory well beneath our producing Opossum Hollow Field in McMullen County, Texas and will likely drill additional wells in the project this year.

- Acquired by farmout significant additional acreage in our Howard Ranch development project in the Wind River Basin in Wyoming and drilled several deep Lance and Mesaverde formation wells.

- Increased the size and capabilities of the DHS Drilling Company fleet from seven rigs at June 30, 2005 to 16 rigs today. Drilling depth capacities range from 7,500' to 25,000'.

- Continued the Company's effort to rationalize its asset base and divest non-core assets. In 2006 we have sold or are under contract to sell properties with total proceeds in excess of $75 million.

- Completed a merger with Castle Energy Corporation and changed the Company's fiscal year end to December 31.

- Received an important favorable ruling in the Company's long-standing breach of contract litigation with the US Department of Interior relating to our leases in the federal waters offshore California.

For 2006 we are executing a drilling capital budget which is expected to be approximately $175 million. The budget is primarily focused on drilling low-risk development wells in Texas, Colorado and Wyoming as well as participating in several high-impact exploratory projects. Within a few months we anticipate initial results from the two wells being drilled in the Columbia River Basin and our first well in the central Utah Hingeline project. These two areas hold the potential for recoverable reserves that compare with some of the largest fields anywhere in the world.

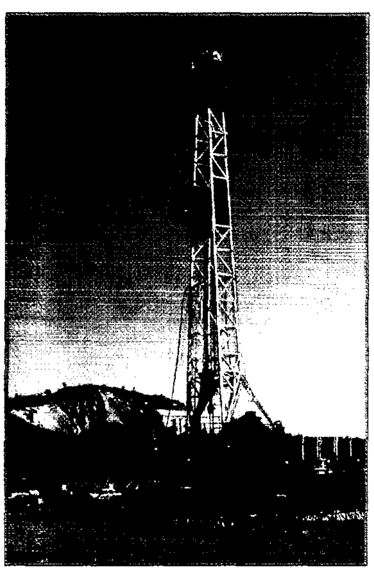
We are in a critical period in our industry wherein the effort to supply energy continues to be challenging due to ever increasing demand growth. Competition will be strong for prospective leasehold, oil and gas field services and technical expertise. We have invested considerable time, money and effort to position Delta to thrive in this environment. Our more than one million acres of undeveloped leasehold is highly prospective and contains significant exposure to both oil and natural gas. DHS Drilling Company provides us access to drilling rigs in a market that continues to be tight. In addition, we have hired some of the best technical people in their respective fields with the intention of building continuous reserve growth. Once again, we owe a debt of appreciation to the employees, the board of directors and the shareholders as we look forward to the remainder of 2006, which should be one of the most exciting years in the Company's history.

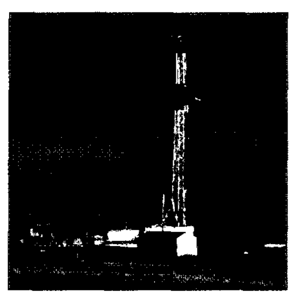
Very truly yours,

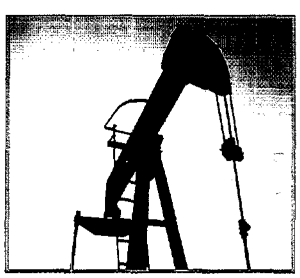
Roger A. Parker
Chairman and Chief Executive Officer

John R. Wallace
President and Chief Operating Officer

August 1, 2006







DESCRIPTION OF BUSINESS

General

Delta Petroleum Corporation is an independent energy 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 the majority 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.

We also have an ownership interest in a drilling company, providing the benefit of full-time access to eleven drilling rigs, primarily in the Rocky Mountain region. We generally 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.

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.

On September 14, 2005, our Board of Directors approved the change of our fiscal year end from June 30 to December 31, effective December 31, 2005.

Overview and Strategy

Our focus is to increase stockholder value by pursuing our corporate strategy of development of our existing properties, reserve growth through repeatable development and operational control, strategic acquisitions in our core areas or in high potential resource plays, and hedging activity directed at limiting cash flow risk.

Concurrent development of our core areas

We intend to simultaneously develop drilling locations in both of our core areas in the near term, although we expect that our drilling efforts and capital expenditures will focus increasingly on the Rockies, where approximately two-thirds of our fiscal 2006 capital budget is allocated and more than one-half of our undeveloped acreage is located. Fields in our core areas provide a multi-year inventory of drilling locations with relatively low geologic risk, and the different well production characteristics of each region allow us to maintain a balance between long-lived reserves and high production rates.

Develop our long-lived Rockies gas projects. We intend to develop our multi-year inventory of drilling locations in the Rocky Mountains. The well performance in our project areas indicates that there are substantial quantities of unproved reserves. Many of our targeted drilling locations are in reservoirs that demonstrate predictable geologic attributes and consistent reservoir characteristics, which typically lead to reliable drilling results.

Increase drilling activity in our Gulf Coast projects. We intend to take advantage of select high impact well locations in three major areas of the Gulf Coast where we predict significant reserves per successful well. Because of the high initial production rates associated with this area, we expect our Gulf Coast drilling activity to result in significant increases in net daily production in the near term.

Reserve growth through repeatable development

We have experienced rapid reserve and production growth over the past three years through a combination of acquisitions and drilling successes. The majority of our reserve and production growth historically has come through acquisitions. In the future we anticipate the majority of our reserve and production growth to come through the execution of our drilling program on a large inventory of proved and unproved locations.

As of December 31, 2005, our reserves were comprised of approximately 181.2 Bcf of natural gas and 14.7 Mmbls of crude oil or 269.4 Mcfe. On an equivalent basis, 67% of our proved reserves were natural gas and 38.5% were

Contract Drilling Operations

In March 2004, we acquired a 50% interest in both Big Dog Drilling Co., LLC ("Big Dog") and Shark Trucking Co., LLC ("Shark") to enable us to have access to drilling rigs and rig transportation facilities on a priority basis. On March 31, 2005, we purchased the remaining interest in Big Dog in exchange for our interest in Shark, one of Big Dog's rigs and related equipment, and 100,000 shares of our stock valued at $1.4 million. On April 15, 2005, we conveyed our interest in Big Dog to DHS Drilling Company ("DHS") in exchange for 4,500,000 shares of DHS's restricted stock, or 90% of its issued and outstanding shares. The remaining 10% was then owned by two officers of DHS who have entered into stock forfeiture agreements with DHS in connection with their employment. Effective May 1, 2005, DHS sold shares of its restricted stock, representing a 45% ownership interest to Chesapeake Energy, Inc. for $15.0 million. Delta currently owns 49.5% of DHS, controls the board of directors and has access to all drilling rigs for Company use and operations.

At December 31, 2005, DHS owned eleven drilling rigs with depth ratings of approximately 7,500 to 20,000 feet. In addition, in early 2006, two additional rigs were acquired. We have the right to use all of the rigs on a priority basis, although approximately half are currently working for third party operators.

The following table presents our utilization rates and rigs available for service for the six months ended December 31, 2005 and the fiscal year ended June 30, 2005:

	Six Months Ended December 31, 2005	Year Ended June 30, 2005[1]
Average number of rigs owned during period	6.4	3.2
Total rig days available[2]	1,178	289
Average drilling revenue per day	$ 13,312	$ 10,280

[1]Includes April 4, 2005 (DHS inception) through June 30, 2005.
[2]Total rig days available includes the number of days each rig was either under contract or available for contract.

On November 9, 2005, DHS acquired 100% of Chapman Trucking for $4.5 million in cash and the results of operations of the entity is included in our consolidated statement of operations since that date. The purpose of the acquisition was to gain ownership, control and access to Chapman's 18 trucks and 37 trailers. Chapman will continue to market trucking services in the Casper, Wyoming area, as well as enter the rig moving market for DHS and third party drilling rigs.

DIRECTORS AND EXECUTIVE OFFICERS

Our executive officers and members of our Board of Directors are as follows:

Name	Age	Positions	Period of Service
Roger A. Parker	44	Chairman, Chief Executive Officer and a Director	May 1987 to Present
John R. Wallace	46	President and Chief Operating Officer	October 2003 to Present
Kevin K. Nanke	41	Treasurer and Chief Financial Officer	December 1999 to Present
Stanley F. Freedman	57	Executive Vice President, General Counsel and Secretary	January 2006 to Present
Kevin R. Collins	49	Director	March 2005 to Present
Jerrie F. Eckelberger	61	Director	September 1996 to Present
Aleron H. Larson, Jr.	60	Director	May 1987 to Present
Russell S. Lewis	51	Director	June 2002 to Present
Jordan R. Smith	71	Director	October 2004 to Present
Neal A. Stanley	58	Director	October 2004 to Present
James P. Van Blarcom	44	Director	July 2005 to Present
James B. Wallace	76	Director	November 2001 to Present

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

Roger A. Parker has been a Director since May 1987 and Chief Executive Officer since April 2002. He served as our President from May 1987 until February 2006 when he resigned to accommodate the appointment of John Wallace to that position. He was named Chairman of the Board on July 1, 2005. Since April 1, 2005, he has also served as Executive Vice President and Director of DHS Drilling Company ("DHS"). Mr. Parker also serves as President, Chief Executive Officer and Director of Amber Resources. He received a Bachelor of Science in Mineral Land Management from the University of Colorado in 1983. He is a member of the Rocky Mountain Oil and Gas Association and is a board member of the Independent Producers Association of the Mountain States (IPAMS). He also serves on other boards, including Community Banks of Colorado.

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. 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 in Geology from Montana State University in 1981. He is a member of the Rocky Mountain Oil and Gas Association, the

American Association of Petroleum Geologists and the Independent Producers Association of the Mountain States. Mr. Wallace is the son of James B. Wallace, a Director of the Company.

Kevin K. Nanke, Treasurer and Chief Financial Officer, joined Delta in April 1995 as our Controller. 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 in Accounting from the University of Northern Iowa in 1989. Prior to working with us, 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 the same date. 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 in Denver, Colorado.

Kevin R. Collins has served as Executive Vice President, Finance and Strategy of KFx Inc. since September 2005. KFx Inc. provides environmental and economic solutions to coal-fired power generating facilities and industrial coal users, and is listed on the American Stock Exchange. From 1995 until 2004 he was Executive Vice President and Chief Financial Officer of Evergreen Resources, Inc., a Denver-based oil and gas company. Evergreen Resources was acquired by Pioneer Natural Resources in September 2004. Mr. Collins became a Certified Public Accountant in 1983 and has over 13 years of 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, Director of Pegasus Technologies, Inc. and Board Member and Chairman of the Finance Committee of Independent Petroleum Association of Mountain States. He received his B.S. 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 present, Mr. Eckelberger has been engaged in the private practice of law and is presently a member of the law firm of Eckelberger & Jackson, LLC. 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.

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, 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. 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 President and CEO of Lewis Capital, LLC which makes private investments in, and provides general business and M&A consulting services to, growth-oriented firms. He has been a member of the board of Delta Petroleum Corporation since June 2002. From February 2002 until January 2005 Mr. Lewis served as Executive Vice President and General Manager of VeriSign Name and Directory Services (VRSN) Group, which managed a significant portion of the internet's critical .com and .net addressing infrastructure. For the preceding 15 years Mr. Lewis managed a wireless transportation systems integration company. Previously 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 Castle Energy Corporation (NASDAQ: CECX) and Advanced Aerations Systems, a privately held firm engaged in subsurface soil treatment. Mr. Lewis has a BA degree in Economics from Haverford College and an MBA from the Harvard School of Business.

Jordan R. Smith is President of Ramshorn Investments, Inc., a wholly owned subsidiary of Nabors Drilling USA LP, 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 Bachelors and Masters degrees in geology from the University of Wyoming in 1956 and 1957, respectively.

Neal A. Stanley founded Teton Oil & Gas Corporation in Denver, Colorado and has served as its President and sole shareholder since 1991. From 1996 to June 2003, he was Senior Vice President - Western Region for Forest Oil Corporation. Since December 2005, Mr. Stanley has served as a member of the Board of Directors and Compensation Committee for Calgary-based Pure Energy Services Ltd., which is listed on the Toronto Stock Exchange under the symbol PSV. Mr. Stanley has approximately thirty years of experience in the oil and gas business. Since 1995, he has been a member of the Executive Committee of the Independent Petroleum Association of Mountain States, and served as its President from 1999 to 2001. Mr. Stanley received a B.S. degree in Mechanical Engineering from the University of Oklahoma in 1975.

James P. Van Blarcom has been Managing Director of The Payne Castle Group, LLC, which has provided sales solutions business development and government affairs services in the cable, high-speed internet and communications industries since 2004. From 1998 to 2004, he was employed by Comcast Cable Communications Management, LLC, a division of Comcast Corporation, where he served as National Telecommunications Manager, Corporate Telecommunications Manager, and finally as Commercial Development Manager, Comcast High-Speed Internet. Mr. Van Blarcom received a B.A. degree in History from Hobart College in 1984.

James B. Wallace has been involved in the oil and gas business for over 40 years and has been a partner of Brownlie, Wallace, Armstrong and Bander Exploration in Denver, Colorado since 1992. From 1980 to 1992 he was Chairman of the Board and Chief Executive Officer of BWAB Incorporated. Mr. Wallace currently serves as a member of the Board of Directors and formerly served as the Chairman of Tom Brown, Inc., an oil and gas exploration company then listed on the New York Stock Exchange. He received a B.S. Degree in Business Administration from the University of Southern California in 1951. James B. Wallace is the father of John R. Wallace, the President of Delta.

MARKET FOR COMMON STOCK AND RELATED STOCKHOLDER MATTER

Delta's common stock currently trades under the symbol "DPTR" on the NASDAQ National 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
September 30, 2003	$ 5.73	$ 4.12
December 31, 2003	6.30	4.75
March 31, 2004	11.19	6.04
June 30, 2004	15.93	10.00
September 30, 2004	$15.47	$10.01
December 31, 2004	16.11	12.67
March 31, 2005	17.07	12.87
June 30, 2005	14.95	8.99
September 30, 2005	$20.82	$14.01
December 31, 2005	22.31	15.07

We have not paid dividends on our common stock and we do not expect to do so in the foreseeable future.

The number of holders of record of our common stock at February 28, 2006 was approximately 800 which does not include an estimated 2,500 additional holders whose stock is held in "street name."

SELECTED FINANCIAL DATA

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

	Six Months Ended December 31,		Years Ended June 30,				
	2005	2004 (Unaudited)	2005	2004	2003	2002	2001
			(In thousands, except per share amounts)				
Total Revenues	$ 61,774	$ 38,864	$ 94,707	$ 36,367	$ 20,718	$ 8,052	$ 12,712
Income (loss) from Continuing Operations	$ (20,518)	$ 10,095	$ 11,276	$ 2,297	$ (241)	$ (6,156)	$ 345
Net Income (Loss)	$ (590)	$ 8,754	$ 15,050	$ 5,056	$ 1,257	$ (6,253)	$ 345
Income/(Loss) Per Common Share							
Basic	$ (.01)	$ .22	$ .37	$ .19	$ .05	$ (.49)	$ .03
Diluted	$ (.01)	$ .21	$ .36	$ .17	$ .05	$ (.49)	$ .03
Total Assets	$ 693,393	$ 326,100	$ 512,983	$ 272,704	$ 86,847	$ 74,077	$ 29,832
Total Liabilities	$ 357,442	$ 109,543	$ 276,746	$ 86,462	$ 38,944	$ 29,161	$ 11,551
Minority Interest	$ 15,496	$ 273	$ 14,614	$ 245	$ -	$ -	$ -
Stockholders' Equity	$ 320,455	$ 216,284	$ 221,623	$ 185,997	$ 47,903	$ 44,916	$ 18,281
Total Long-Term Liabilities	$ 257,743	$ 85,925	$ 222,596	$ 72,172	$ 33,082	$ 24,939	$ 9,434

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Overview

We are a Denver, Colorado based independent energy 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 Gulf Coast and Rocky Mountain regions, which comprise the majority 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, 2005, we had estimated proved reserves that totaled 269.4 Bcfe, of which 38.5% were proved developed, with an after-tax PV-10 value of $760.6 million. As of December 31, 2005, we achieved net production of 56.0 Mmcfe per day.

As of December 31, 2005, our reserves were comprised of approximately 181.2 Bcf of natural gas and 14.7 Mmbbls of crude oil, or 67.2% gas on an equivalent basis. Approximately 48% of our proved reserves were located in the Gulf Coast, 38% in the Rocky Mountains, and 14% in other locations. We expect that our drilling efforts and capital expenditures will focus increasingly on the Rockies, where approximately two-thirds of our fiscal 2006 capital budget is allocated and more than one-half of our undeveloped acreage is located. As of December 31, 2005, we controlled approximately 990,000 undeveloped acres, representing in excess of 96% 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 90% as of December 31, 2005. 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. We also have a controlling ownership interest in a drilling company, providing the benefit of access to 11 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.

For calendar year 2006, we have preliminarily established a drilling budget of approximately $150.0 to $195.0 million. We are concentrating a substantial portion of this budget on the development of our Newton, Opossum Hollow, and Midway Loop Fields in the Gulf Coast region, the Howard Ranch Field in the Wind River Basin in central Wyoming, the Vega Unit and PGR properties of the Piceance Basin in western Colorado, and our central Utah play acquired subsequent to year-end. State of the art geologic and seismic geophysical modeling indicates that these fields have target geologic formations containing substantial hydrocarbon deposits that can be economically developed. Recently completed successful wells in several of these Rocky Mountain development programs have found multiple accumulations of tight sand reservoirs at various depths, characterized by low permeability and high pressure. These types of reservoirs possess predictable geologic attributes and consistent reservoir characteristics, which result in a higher drilling success rate and lower per well cost and risk.

The exploration for and the acquisition, development, production, and sale of, natural gas and crude oil is 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 profitability and long-term value creation for stockholders. Generating reserve and production growth while containing costs represents an ongoing focus for management, and is made particularly important in our business by the natural production and reserve decline associated with oil and gas properties. In addition to developing new reserves, we compete to acquire additional reserves, which involve judgments regarding recoverable reserves, future oil and gas prices, operating costs and potential environmental and other liabilities, title issues and other factors. During periods of historically high oil and gas prices, third party contractor and material cost increases are more prevalent due to increased competition for goods and services. Other challenges we face include attracting and retaining qualified personnel, gaining access to equipment and supplies and maintaining access to capital on sufficiently favorable terms.

We have taken the following steps to mitigate the challenges we face. We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, typically costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our review of market conditions, available hedge prices and our operating strategy. Our current derivative contracts cover approximately 32% of our estimated 2006 oil and gas production. Our interest in a drilling and trucking company allows us to mitigate the increasing challenge for rig availability in the Rocky Mountains and also helps to control third party contractor and material costs. Our business strengths include a multi-year inventory of attractive drilling locations and a diverse balance of high return Gulf Coast properties and long lived Rockies reserves, allowing us to grow reserves and replace and expand production organically without having to rely solely on acquisitions.

Recent developments

During the six months ended December 31, 2005, we achieved the following:

- Successfully closed $100.0 million private placement of common stock to fund the acquisition discussed below.
- Acquired 145,000 net undeveloped acres in the Columbia River Basin in Washington and an interest in 6,314 gross acres that are currently being developed in the Piceance Basin in Colorado for $85.0 million.
- Successfully divested of the Deerlick Creek field in Tuscaloosa County, Alabama for net proceeds of $28.9 million resulting in a gain on sale of oil and gas properties of $10.2 million, net of tax and divested other non-core properties for proceeds of $5.3 million and a gain on sale of $1.6 million, net of tax.
- Successfully closed bank financing arrangement for DHS with Guggenheim Corporate Funding, LLC ("Guggenheim") for $35.0 million and completed the $4.5 million acquisition of Chapman Trucking, which ensures rig mobility for DHS rigs.
- Increased reserves to 269.4 Bcfe at December 31, 2005, an increase of 20.1% compared to reserves as of June 30, 2005 of 224.3 Bcfe.

Results of Operations

The following discussion and analysis relates to items that have affected our results of operations for the six months ended December 31, 2005 and 2004, and the fiscal years ended June 30, 2005, 2004 and 2003. 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 Transition Report on Form 10-K.

	Six Months Ended December 31,		Years Ended June 30,		
	2005	2004 (Unaudited)	2005	2004	2003
Revenue:					
Oil and gas sales	$ 60,656	$ 39,657	$ 90,871	$ 37,226	$ 22,576
Contract drilling and trucking fees	9,096	300	4,796	-	-
Realized loss on derivative instruments, net	(7,978)	(93)	(960)	(859)	(1,858)
Total Revenue	61,774	39,864	94,707	36,367	20,718
Operating Expenses:					
Lease operating expense	9,434	6,051	15,566	7,530	6,966
Transportation expense	829	172	575	259	230
Production taxes	3,541	2,906	6,128	1,978	1,214
Depreciation, depletion and amortization – oil and gas	17,577	8,273	21,682	9,900	4,999
Depreciation and amortization – drilling and trucking	2,847	386	1,525	14	-
Exploration expense	3,411	1,283	6,155	2,406	140
Dry hole costs	4,073	2,673	2,771	2,132	537
Drilling and trucking operations	5,821	1,074	4,666	232	-
Professional fees	2,264	847	2,010	1,174	842
General and administrative	14,227	6,104	14,920	6,875	4,295
Total operating expenses	64,024	29,769	75,998	32,500	19,223
Operating income (loss)	(2,250)	10,095	18,709	3,867	1,495
Other income and (expense):					
Other income (expense)	173	(149)	(492)	122	31
Gain on sale of marketable securities, net of tax	1,194	-	-	-	-
Unrealized loss on derivative contracts, net	(9,872)	-	-	-	-
Minority interest	(688)	315	1,017	70	-
Interest and financing costs	(9,075)	(2,236)	(7,958)	(1,762)	(1,767)
Total other expense	(18,268)	(2,070)	(7,433)	(1,570)	(1,736)

Income (loss) from continuing operations before income taxes and discontinued operations	(20,518)	8,025	11,276	2,297	(241)
Income tax benefit	7,639	-	3,325	-	-
Net income (loss) from continuing operations	(12,879)	8,025	14,601	2,297	(241)
Income from discontinued operations of properties sold, net of tax	501	729	449	872	1,241
Gain on sale of oil and gas properties, net of tax	11,788	-	-	1,887	277
Cumulative effect of change in accounting principle, net of tax	-	-	-	-	(20)
Net income (loss)	$ (590)	$ 8,754	$ 15,050	$ 5,056	$ 1,257

Six Months Ended December 31, 2005 Compared to Six Months Ended December 31, 2004 (Unaudited)

Net Income. Net income decreased $9.5 million to a net loss of $590,000 or $.01 per diluted common share for the six months ended December 31, 2005, as compared to net income of $8.8 million or $.21 per diluted common share for the six months ended December 31, 2004. This decrease was primarily due to a $9.9 million non-cash loss for ineffective hedges, $8.0 million of realized losses on hedging contracts, higher exploration and dry hole costs, increased general and administrative expenses of $8.1 million due to the growth in the Company's operations and activities, and increased interest and financing costs of $6.8 million due to higher average debt outstanding.

Revenue. During the six months ended December 31, 2005, oil and natural gas revenue from continuing operations increased 53% to $60.7 million, as compared to $39.7 million for the six months ended December 31, 2004. The increase was the result of (i) an average onshore gas price received during the six months ended December 31, 2005 of $8.82 per Mcf compared to $5.83 per Mcf received in the six months ended December 31, 2004, (ii) an increase in average onshore oil price received in the six months ended December 31, 2005 of $59.42 per Bbl compared to $44.64 per Bbl during the same period in 2004, (iii) an increase in offshore oil price received of $48.98 per Bbl during the six months ended December 31, 2005 compared to $30.66 during the six months ended December 31, 2004, and (iv) a 7.6% increase in average daily production over the six months ended December 31, 2004.

Cash payments required on our hedging activities impacted revenues during the six months ended December 31, 2005 and 2004. The cost of settling our hedging activities was $8.0 million and $93,000 during the six months ended December 31, 2005 and 2004, respectively.

Contract Drilling and Trucking Fees. At December 31, 2005 DHS owned eleven drilling rigs with depth ratings of approximately 7,500 to 20,000 feet. In addition, in early 2006, two additional rigs were acquired. We have the right to use all of the rigs on a priority basis, although approximately half are currently working for third party operators.

Drilling revenues for the six months ended December 31, 2005 increased to $9.1 million compared to $300,000 for the prior year period. Drilling revenue is earned under daywork contracts where we provide a drilling rig with required personnel to our third party customers, who supervise the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is in use. During the mobilization period we typically earn a fixed amount of revenue based on the mobilization rate set in the contract. Drilling revenues earned on wells drilled for Delta have been eliminated through consolidation. At December 31, 2005 there were eight DHS rigs in operation compared to four rigs in operation at June 30, 2005.

Trucking revenues were insignificant during the six months ended December 31, 2005 as the Chapman acquisition was completed in November.

Production and Cost Information

Production volumes, average prices received and cost per equivalent Mcf for the six months ended December 31, 2005 and 2004 are as follows:

	Six Months Ended December 31,			
	2005		2004	
	Onshore	Offshore	Onshore	Offshore
Production:				
Oil (MBbl)	428	81	430	74
Gas (MMcf)	3,565	-	3,123	-
Production – Discontinued Operations:				
Oil (MBbl)	-	-	19	-
Gas (MMcf)	155	-	174	-
Average Price – Continuing Operations:				
Oil (per barrel)	$ 59.42	$ 48.98	$ 44.64	$ 30.66
Gas (per Mcf)	$ 8.82	$ -	$ 5.83	$ -
Costs per Mcfe				
Hedge effect	$ (1.18)	$ -	$ (.02)	$ -
Lease operating expense	$ 1.17	$ 4.62	$ 0.78	$ 3.57
Production taxes	$ .60	$ (.23)	$ .51	$ .06
Transportation costs	$ .14	$ -	$ .03	$ -
Depletion expense	$ 2.24	$ .61	$ 1.33	$ .75

Lease Operating Expense. Lease operating expenses for the six months ended December 31, 2005 were $9.4 million compared to $6.1 million for the same period a year earlier. Lease operating expense from continuing operations for onshore properties for the six months ended December 31, 2005 was $1.17 per Mcfe as compared to $0.78 per Mcfe for the same period a year earlier. Lease operating expense from continuing operations for offshore properties was $4.62 per Mcfe for the six months ended December 31, 2005 and $3.57 per Mcfe for the same period a year earlier. This increase in lease operating costs from continuing operations per Mcfe can be primarily attributed to the increase in the percentage of wells owned in the Gulf coast region, largely due to the Manti acquisition in January 2005, as compared to our other regions. Our Gulf Coast properties typically have higher average lease operating costs. Recently, Newton has experienced substantial costs related to compression and salt water hauling and disposal.

Depreciation, Depletion and Amortization – oil and gas. Depreciation, depletion and amortization expense increased 112% to $17.6 million in the six months ended December 31, 2005, as compared to $8.3 million for the six months ended December 31, 2004. Depreciation, depletion and amortization expenses for our onshore properties increased to $2.24 per Mcfe during the six months ended December 31, 2005 from $1.33 per Mcfe for the six months ended December 31, 2004. Depletion rates have increased based on the higher amounts paid to acquire reserves in the ground and the increase in drilling costs relative to reserve additions. We also incurred higher depletion rates caused by lower proved developed producing reserves in our South Angleton and Padgett fields. The reduction in the South Angleton field was from unsuccessful drilling results, while the reduction in reserves in the Padgett field was from a seismic survey that indicated a smaller reservoir than originally anticipated.

Depreciation and Amortization – drilling and trucking. Depreciation and amortization expense – drilling and trucking increased to $2.8 million for the six months ended December 31, 2005 as compared to $386,000 for the prior year period. This increase can be attributed to additional rigs acquired by DHS Drilling Company.

Dry Hole Costs. We incurred dry hole costs of approximately $4.1 million for the six months ended December 31, 2005 compared to $2.7 million for the same period a year ago. During 2004, a significant portion of these costs related to our Trail Blazer prospect in Laramie County, Wyoming and four non-Niobrara formation dry holes in Washington County, Colorado. During the six months ended December 31, 2005, four dry holes were drilled including two in Washington County, Colorado, one in Utah, and one in Orange County, California.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the six months ended December 31, 2005 were $3.4 million compared to $1.3 million for the six months ended December 31, 2004. The increase in exploration costs was primarily related to seismic costs and impairment of prospect acquisition costs. During the six months ended December 31, 2005, our most significant exploration cost related to the $1.4 million Newton 3D seismic shoot covering 58 square miles which was completed and processed during 2005 and which will assist us in prioritizing our drilling locations and identifying new target formations in 2006. In addition, we acquired 2D data in the Gulf Coast region and also began acquiring geophysical data on the Columbia River Basin properties in the state of Washington.

During the six months ended December 31, 2005, a dry hole was drilled on a prospect located in Orange County, California. Based on drilling results and evaluation of the Prospect, we determined that we would not pursue development and accordingly an impairment was recorded. Included in our exploration expense for the six months ended December 31, 2005 is $1.3 million for the full impairment of the remaining leasehold costs related to the prospect.

Drilling and Trucking Operations. We had drilling and trucking operations of $5.8 million during the six months ended December 31, 2005 compared to $1.1 million during the six months ended December 31, 2004. The significant increase in expenses was due to an increase in the number of rigs in operation, eight rigs as of December 31, 2005 compared to two rigs at December 31, 2004.

Professional Fees. Professional fees include corporate legal costs, accounting fees, shareholder relations consultants and legal fees for representation in negotiations and discussions with various state and federal governmental agencies relating to our undeveloped offshore California leases. Our professional fees increased 167% to $2.3 million for the six months ended December 31, 2005, as compared to $847,000 for the six months ended December 31, 2004. The increase in professional fees can be attributed largely to compliance with the Sarbanes-Oxley Act and also to annual fees incurred over the shorter six month transition period ended December 31, 2005 without a corresponding reduction in fees.

General and Administrative Expense. General and administrative expense increased 133% to $14.2 million for the six months ended December 31, 2005 as compared to $6.1 million for the six months ended December 31, 2004. The increase in general and administrative expenses is primarily attributed to (i) $2.1 million of stock option compensation expense related to the adoption of SFAS No. 123R, (ii) a 60% increase in technical and administrative staff and related personnel costs, (iii) the expansion of our office facility and (iv) $715,000 of vested restricted stock and option awards granted to officers, directors and management.

Gain on Sale of Marketable Security. During the six months ended December 31, 2005, the Company sold investment securities classified as available-for-sale securities resulting in a realized gain of $1.2 million.

Unrealized Losses on Derivative Contracts, Net. During the six months ended December 31, 2005, our gas derivative contracts became ineffective and no longer qualified for hedge accounting. Hedge ineffectiveness results from different changes in the NYMEX contract terms and the physical location, grade and quality of our oil and gas production. The change in fair value of our gas contracts in the six month period are reflected in earnings, as opposed to being recorded in other comprehensive income (loss), a component of stockholders' equity. As a result, we recognized an $9.9 million non-cash loss in our statement of operations. As commodity prices fluctuate, we will record our gas derivative contracts at market value with any changes in market value recorded through unrealized gain (loss) on derivative contracts in our statement of operations. Our oil derivative contracts continue to qualify for hedge accounting.

Minority Interest. Minority interest represents the minority investors' percentage of their share of income or losses from Big Dog, Shark or DHS in which they hold an interest. During the six months ended December 31, 2004, Big Dog and Shark incurred operating losses. During the six months ended December 31, 2005, DHS generated an operating profit.

Interest and Financing Costs. Interest and financing costs increased 306% to $9.1 million for the six months ended December 31, 2005, as compared to $2.2 million for the six months ended December 31, 2004. The increase is primarily related to interest on the $150.0 million senior notes that were issued in March 2005, the increase in the average amount outstanding under our credit facility primarily as a result of the Manti acquisition completed in January 2005 and our increased investment in the Columbia River prospect in Washington completed in April 2005. In addition, borrowings of $35.0 million by DHS have also resulted in increased interest expense.

Income tax benefit. Prior to June 30, 2005, the Company recorded a full valuation allowance on its deferred tax assets and accordingly, during the six months ended December 31, 2004, no income tax provision was recorded. During the six months ended December 31, 2005, an income tax benefit of $7.6 million was recorded for continuing operations at an effective tax rate of 37.2%.

Discontinued Operations. On September 2, 2005, we completed the sale of our Deerlick Creek field in Tuscaloosa County, Alabama for $30.0 million with an effective date of July 1, 2005. We recorded a gain on sale of oil and gas properties of $10.2 million on net proceeds of $28.9 million after normal closing adjustments. The results of operations on these assets during the six months ended December 31, 2005 was $501,000. During October 2005, we sold at auction our interests in several non-strategic fields for proceeds of $5.3 million and a gain of $1.6 million.

Fiscal 2005 Compared to Fiscal 2004

Net Income. Net income increased $10.0 million to $15.1 million or $.36 per diluted common share for fiscal 2005, an increase of 198% as compared to $5.1 million or $.17 per diluted common share for fiscal 2004. This increase was primarily due to a 91% increase in production relating to the Alpine acquisition completed during fiscal 2004, the Manti acquisition completed during fiscal 2005 and the development of our undeveloped properties.

Revenue. During fiscal 2005, oil and natural gas revenue from continuing operations increased 144% to $90.9 million, as compared to $37.2 million in fiscal 2004. The increase was the result of (i) an average onshore gas price received in fiscal 2005 of $5.79 per Mcf compared to $5.27 per Mcf in 2004, (ii) an increase in average onshore oil price received in fiscal 2005 of $47.05 per Bbl compared to $33.09 per Bbl in 2004, (iii) an increase in offshore oil price received of $33.37 per Bbl in fiscal 2005 compared to $22.11 in 2003, and (iv) a 91% increase in average daily production over the prior year.

Cash payments required on our hedging activities impacted revenues in 2005 and 2004. The cost of settling our hedging activities was $960,000 in fiscal 2005 and $859,000 in fiscal 2004.

Production volumes, average prices received and cost per equivalent Mcf for the years ended June 30, 2005 and 2004 are as follows:

	Years Ended June 30,			
	2005		2004 (1)	
	Onshore	Offshore	Onshore	Offshore
Production:				
Oil (MBbl)	899	156	552	180
Gas (MMcf)	7,501	-	2,841	-
Production – Discontinued Operations:				
Oil (MBbl)	2	-	16	-
Gas (MMcf)	174	-	269	-
Average Price – Continuing Operations:				
Oil (per barrel)	$ 47.05	$ 33.37	$ 33.09	$ 22.11
Gas (per Mcf)	$ 5.79	$ -	$ 5.27	$ -
Costs per Mcfe				
Hedge effect	$ (.07)	$ -	$ (.14)	$ -
Lease operating expense	$ .92	$ 4.00	$ .70	$ 2.98
Production taxes	$ .46	$ .21	$ .31	$ .04
Transportation costs	$ .04	$ -	$ .04	$ -
Depletion expense	$ 1.57	$ .77	$ 1.46	$ .65

(1) 2004 information has been changed to comply with FAS 144 "Accounting for the Impairment or Disposal of Long-Lived Assets."

Lease Operating Expense. Lease operating expenses for the year ended June 30, 2005 were $15.6 million compared to $7.5 million for the same period a year earlier. Lease operating expense from continuing operations for onshore properties for the year ended June 30, 2005 was $.92 per Mcfe as compared to $.70 per Mcfe for the same period a year earlier. Lease operating expense from continuing operations for offshore properties was $4.00 per Mcfe for the year ended June 30, 2005 and $3.76 per Mcfe for the same period a year earlier. This increase in lease operating costs from continuing operations per Mcfe can be primarily attributed to the completion of the Manti acquisition in January 2005 and the Alpine acquisition in June 2004. The assets acquired in these two transactions have higher production costs than the asset base previously owned.

Depreciation and Depletion Expense. Depreciation and depletion expense increased 134% to $23.2 million in fiscal 2005, as compared to $9.9 million in fiscal 2004. Depreciation and depletion expenses for our onshore properties increased to $1.57 per Mcfe during fiscal 2005 from $1.46 per Mcfe in fiscal 2004. Depletion rates have increased based on the higher amounts paid to acquire reserves in the ground and the increase in drilling costs. In addition, we incurred higher depletion rates caused by lower proved developed producing reserves in our South Angleton and Padgett fields. The reduction in the South Angleton field was from unsuccessful drilling results, while the reduction in reserves in the Padgett field was from a seismic survey that indicated a smaller reservoir than originally anticipated. Our depletion rate in our Newton field also increased as a result of drilling and completing inefficiencies and under-performing wells. Our last two wells which were completed in late June were on budget and had predictable initial results. We anticipate overall depletion rates for us and our competitors to increase under the current pricing environment.

Dry Hole Costs. We incurred dry hole costs of approximately $2.8 million for the year ended June 30, 2005 compared to $2.1 million for the same period a year ago. A significant portion of these costs relate to our Trail Blazer prospect in Laramie County, Wyoming. Included in the dry holes were four non-Niobrara formation dry holes in Washington County, Colorado.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the year ended June 30, 2005 were $6.2 million compared to $2.4 million for the prior year. Current year activities include newly acquired seismic information in Washington County, Colorado, Polk County, Texas and Laramie County, Wyoming.

Drilling and Trucking Operations. We had drilling and trucking operations of $4.7 million during the year ended June 30, 2005 compared to $232,000 during the year ended June 30, 2004. The significant increase in expenses was due to an increase in the number of rigs in operation.

Professional Fees. Professional fees include corporate legal costs, accounting fees, shareholder relations consultants and legal fees for representation in negotiations and discussions with various state and federal governmental agencies relating to our undeveloped offshore California leases. Our professional fees increased 71% to $2.0 million for fiscal 2005, as compared to $1.2 million for fiscal 2004. The increase in professional fees can be attributed largely to compliance with the Sarbanes-Oxley Act.

General and Administrative Expense. General and administrative expense increased 116% to $14.9 million in fiscal 2005, as compared to $6.9 million in fiscal 2004. The increase in general and administrative expenses is primarily attributed to (i) the 95% increase in technical and administrative staff and related personnel costs, (ii) the expansion of our office facility and (iii) $824,000 of vested restricted stock and option awards granted to officers, directors and management.

Minority Interest. Minority interest represents the minority investors' percentage of their share of income or losses from Big Dog, Shark or DHS in which they hold an interest.

Interest and Financing Costs. Interest and financing costs increased 352% to $8.0 million in fiscal 2005, as compared to $1.8 million in fiscal 2004. The increase is primarily related to the $150.0 million senior note offering completed in March 2005 and the increase in the average amount outstanding under our credit facility primarily as a result of the Manti acquisition completed in January 2005 and our increased investment in the Columbia River prospect in Washington completed in April 2005.

Fiscal 2004 Compared to Fiscal 2003

Net income. Net income increased $3.8 million to $5.1 million or $.17 per diluted common share for fiscal 2004, an increase of 302% as compared to $1.3 million or $.05 per diluted common share for fiscal 2003. This increase was primarily due to a 40% increase in production from fiscal 2003 relating to acquisitions completed during fiscal 2004 and 2003, the development of undeveloped properties associated with these acquisitions and an increase in average oil and natural gas prices received by Delta.

Revenue. During fiscal 2004, oil and natural gas revenue from continuing operations increased 65% to $37.2 million, as compared to $22.6 million in fiscal 2003. The increase was the result of (i) an average for onshore gas price received in fiscal 2004 of $5.27 per Mcf compared to $4.71 per Mcf in 2003, (ii) an increase in average onshore oil price received in fiscal 2004 of $33.09 per Bbl compared to $28.82 per Bbl in 2003, (iii) a slight increase in offshore oil price received of $22.11 per Bbl in fiscal 2004 compared to $20.21 in 2003 and (iv) a 40% increase in average daily production during the fiscal year previously discussed above.

Cash payments required on our hedging activities impacted revenues in 2004 and 2003. The cost of settling our hedging activities was $859,000 in fiscal 2004 and $1.9 million in fiscal 2003.

Production volumes, average prices received and cost per equivalent Mcf for the years ended June 30, 2004 and 2003 were as follows:

	Years Ended June 30,			
	2004 (1)		2003 (1)	
	Onshore	Offshore	Onshore	Offshore
Production:				
Oil (MBbl)	552	180	217	227
Gas (MMcf)	2,841	-	2,492	-
Production – Discontinued Operations:				
Oil (MBbl)	16	-	35	-
Gas (MMcf)	269	-	446	-
Average Price – Continuing Operations:				
Oil (per barrel)	$ 33.09	$ 22.11	$ 28.82	$ 20.21
Gas (per Mcf)	$ 5.27	$ -	$ 4.71	$ -
Costs per Mcfe				
Hedge effect	$ (.14)	$ -	$ (.49)	$ -
Lease operating expense	$ .70	$ 2.98	$ .99	$ 2.35
Production taxes	$ .31	$ .04	$ .30	$ .05
Transportation costs	$ .04	$ -	$ .06	$ -
Depletion expense	$ 1.46	$ .65	$ 1.02	$ .79

(1) 2004 and 2003 information has been changed to comply with FAS 144 "Accounting for the Impairment or Disposal of Long-Lived Assets."

Lease Operating Expense. Lease operating expense increased 8% to $7.5 million for fiscal 2004, as compared to $7.0 million for 2003; however, onshore lease operating costs per Mcfe decreased from $.99 per Mcfe in fiscal 2003 to $.70 per Mcfe in fiscal 2004. This decrease in production cost per Mcfe can primarily be attributed to our Padgett Field acquisition completed during fiscal 2003. The Padgett Field added an additional 1.2 Bcfe to current year production with an associated cost of $.22 per Mcfe.

Depreciation and Depletion Expense. Depreciation and depletion expense increased 96% to $9.9 million in fiscal 2004, as compared to $5 million in fiscal 2003. Depreciation and depletion expenses per Mcfe for our onshore properties increased to $1.46 per Mcfe during fiscal 2004 from $1.02 per Mcfe in fiscal 2003. This increase can be attributed to the acquisition of our Christensen Field in Washington County which had a depreciation and depletion expense of $2.40 per Mcfe and the acquisition of our Eland and Stadium fields which had depreciation and depletion expense of $2.74 per Mcfe.

Dry Hole Costs. We incurred dry hole costs of $2.1 million on five exploratory wells in fiscal 2004 and $537,000 on three exploratory wells in fiscal 2003.

Exploration Expenses. Exploration expenses consist of geological and geophysical costs and lease rentals. Our exploration costs for fiscal 2004 of $2.4 million included an extensive 78 square mile seismic shoot in Washington County, Colorado on our South Tongue Prospect.

Drilling and Trucking Operations. In March 2004, we acquired a 50% interest in both the Big Dog Drilling Co., LLC and Shark Trucking Co., LLC. We began drilling our first well with a Big Dog rig in August 2004 and will primarily drill on our acreage. The cost associated with these two entities represents start up costs incurred through year end.

Professional Fees. Professional fees include corporate legal costs, accounting fees, shareholder relations consultants and legal fees for representation in negotiations and discussions with various state and federal governmental agencies relating to our undeveloped offshore California leases. Our professional fees increased 43% to $1.2 million for fiscal 2004, as compared to $842,000 for fiscal 2003. The increase in professional fees can be attributed largely to the compliance with the Sarbanes-Oxley Act.

General and Administrative Expense. General and administrative expense increased 60% to $6.9 million in fiscal 2004, as compared to $4.3 million in fiscal 2003. The increase in general and administrative expenses is primarily attributed to (i) the increase in technical and administrative staff and related personnel costs, (ii) the expansion of our office facility and (iii) additional bonuses earned by officers and management.

Interest and Financing Costs. Interest and financing costs remained consistent with fiscal 2003. We expensed $1.8 million for both fiscal 2004 and 2003. The decrease in interest rates during fiscal 2004 was offset by the increase in long-term debt obligations during the year.

Discontinued Operations. Included in discontinued operations are (i) income (loss) from operations of properties sold and (ii) gain (loss) on sale of oil and gas properties. We are required to re-class related revenue and expenses relating to sales of our oil and gas properties for all periods presented. During fiscal 2004, we sold our Pennsylvania properties which resulted in a gain on sale of $1.9 million. During fiscal 2003, we sold some non-strategic oil and gas properties which resulted in a gain of $277,000.

Liquidity and Capital Resources

Liquidity is a measure of a company's ability to access cash. 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 and the sale of oil and gas properties, and through borrowings under our credit facility. On March 15, 2005, we issued 7% senior notes, unsecured, for aggregate net proceeds of $149.3 million. At the same time, we also increased our credit facility to $200.0 million with an available borrowing base of $75.0 million, $10.7 million of which was not drawn at December 31, 2005. On September 27, 2005, we completed a private placement of 5,405,418 shares of our common stock to twenty-seven institutional investors at a price of $18.50 per share in cash for gross proceeds of $100.0 million and net proceeds of $95.0 million. The majority of the proceeds were immediately used to acquire additional oil and gas properties. On September 2, 2005 we sold our non-core Deerlick Field located in Tuscaloosa, Alabama for $28.9 million, subject to certain normal closing adjustments and on September 30, 2005, DHS completed a five-year financing arrangement for $35.0 million. Subsequent to year end, we sold certain non-operated properties (subject to certain normal closing adjustments) and issued common stock for net proceeds of $37.0 million.

The prices we receive for future oil and natural gas production and the level of production have a significant impact on 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 production activities in generating additions to production.

We continue to examine alternative sources of long-term capital, including bank borrowings, the issuance of debt instruments, the sale of preferred and common stock, the sales of non-strategic assets, and joint venture financing. Availability of these sources of capital and, therefore, our ability to execute our operating strategy will depend upon a number of factors, some of which are beyond our control.

We believe the availability under our Revolving Credit Facility, projected operating cash flows, additional debt and equity financings and cash on hand will be sufficient to meet the requirements of our business; however, future cash flows are subject to a number of variables, including the level of production and oil and natural gas prices. We cannot give assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or that increased capital expenditures will not be undertaken. Actual levels of capital expenditures may vary significantly due to a variety of factors, including but not limited to, drilling results, product pricing and future acquisition and divestitures of properties.

Company Acquisitions and Growth

We continue to evaluate potential acquisitions and property development opportunities. During the last eighteen months ended December 31, 2005, we completed the following transactions:

During December 2005, Delta transferred its ownership in approximately 427,000 gross acres (64,000 net acres) of non-operated interests in the Columbia River Basin to a newly created wholly owned subsidiary, CRB Partners, LLC ("CRBP"). In January 2006, Delta sold a minority interest in CRBP to a small group of investors. The Company expects to record a gain during the first quarter of 2006 as a result of closing this transaction. The Company plans to use the proceeds from such sale to initially reduce borrowings under its senior secured debt facility and to later accelerate its rate of development drilling. As a result of the transaction, Delta now owns a net interest of just over 40,000 acres in the Columbia River Basin through its remaining ownership of CRBP and additional interests in 332,000 net acres in the Columbia River Basin from previous transactions.

On November 9, 2005, DHS acquired 100% of Chapman Trucking ("Chapman") for $4,500,000 in cash and the results of operations of the entity is included in the Company's consolidated statement of operations since that date. The purchase was for 18 trucks and 37 trailers. Chapman will continue to market trucking services in the Casper, Wyoming area, as well as enter the rig moving market for DHS and third party drilling rigs.

On September 29, 2005 the Company acquired an undivided 50% working interest in approximately 145,000 net undeveloped acres in the Columbia River Basin in Washington, and an interest in undeveloped acreage in the Piceance Basin in Colorado from Savant Resources, LLC ("Savant") for an aggregate purchase price of $85.0 million in cash. The majority of the acquired acreage in the Columbia River Basin consolidates the Company's current leasehold position. This acquisition included a small portion of acreage that is subject to an agreement with EnCana Oil & Gas (USA) Inc., whereby the Company has the right to convert an overriding royalty interest to a working interest at project payout. In the Piceance Basin, the Company acquired Savant's interest in an entity that owns a 25% interest in approximately 6,314 gross acres that is currently being developed. The acquisition was funded through the issuance of securities discussed below.

On September 27, 2005, we completed a private placement of 5,405,418 shares of our common stock to twenty-seven institutional investors at a price of $18.50 per share in cash for gross proceeds of $100.0 million and net proceeds of $95.0 million. The proceeds were primarily used to fund the Savant transaction discussed above.

On May 4, 2005, we purchased from Savant a 14.25% back-in after project payout working interest in approximately 427,000 acres in the Columbia River Basin for $18.2 million in cash. The acreage is in close proximity to many of our existing leasehold interests in the basin and includes a lease on which another operator is currently drilling. The interest acquired is a non-cost bearing interest with a back-in after project payout. We can, however, at any time and at our discretion, convert the interest to a cost bearing working interest by paying our proportionate share of the costs incurred in the project.

On March 31, 2005, we purchased the remaining interest in Big Dog in exchange for our interest in Shark, one of Big Dog's rigs, certain related equipment and 100,000 shares of our restricted stock valued at $1.4 million. On April 15, 2005, we conveyed our interest in Big Dog to DHS in exchange for 4,500,000 shares of DHS restricted stock, or 90% of its issued and outstanding shares. On May 16, 2005, DHS sold 45% of its restricted stock to Chesapeake Energy, Inc. for $15 million. We currently own 49.5% of DHS. We control the board of directors and operations and have a right to the use of their rigs. As such, the operations of DHS have been consolidated into the Company.

On January 4, 2005 we acquired additional interests in the South Tongue area of Washington County and also entered into an exploration agreement for properties in Orange County, California. We paid $400,000 in cash and 135,836 shares of our common stock valued at $2.0 million, of which $1.1 million was attributable to South Tongue.

On December 15, 2004, we entered into a purchase and sale agreement to acquire substantially all of the oil and gas assets owned by several entities related to Manti Resources, Inc., which was an unaffiliated, privately held Texas corporation ("Manti"). The adjusted purchase price was $59.7 million. The entire amount of the purchase price was paid in cash at the closing of the transaction, which occurred on January 21, 2005. The purchase price for the Manti properties was determined through arms-length negotiations. The purchase price was paid with increased borrowings from our existing bank credit facility. Substantially all of the assets that we acquired from Manti have been pledged as collateral under our credit facility.

On November 4, 2004, we entered into an agreement with Edward Mike Davis, LLC to acquire the balance of its back-in working interest and his overriding royalty interest in all of his ownership to the base of the Niobrara formation in the South Tongue interests in Washington County, Colorado. This agreement eliminated all future drilling commitments in Washington County. This included approximately 260,000 acres of leasehold. In addition, we acquired a 100% working interest with a 70% net revenue interest in the Magers 1-9 well in Colusa County, California. Total consideration was 650,000 shares of our common stock valued at approximately $9.4 million. Also on November 4, 2004, we entered into an agreement with Davis to acquire and possibly develop certain areas in Elbert County, Colorado. The initial cost of this transaction was 25,000 shares of our common stock valued at approximately $363,000.

On September 15, 2004, we acquired seven wells in Karnes County, Texas from an unrelated entity and an unrelated individual for $5.0 million in cash.

On July 1, 2004, we acquired certain interests in California's Sacramento Basin and a 7.5% reversionary working interest in the South Tongue interests in Washington County, Colorado from Edward Mike Davis, LLC, which was then a greater than 5% stockholder, for 760,000 shares of our common stock valued at $10.4 million using the five-day closing price before and after the terms of the agreement were agreed and closed, which was $13.63.

Historical Cash Flow

Our cash flow from operating activities increased 28% to $24.9 million for the six months ended December 31, 2005 compared to $19.4 million for the same period a year earlier, primarily as a result of a 53% increase in revenue and a 137% increase in non-cash depletion expense. Our net cash used in investing activities increased by 341% to $146.5 million for the six months ended December 31, 2005 compared to $33.2 million for the same period a year earlier. The increase in cash used for investing activity can be attributed to the expansion of our drilling programs in both the Rocky Mountain and Gulf Coast regions along with additional drilling rig acquisitions. Cash flow from financing activities increased to $124.9 million for the six months ended December 31, 2005 compared to $13.5 million for the same period the prior year. During the six months ended December 31, 2005, we financed our operations, acquisitions, and capital expenditures primarily with net proceeds of $95.0 million in newly issued equity and $29.2 million in net debt additions.

Our cash flow from operating activities increased 366% to $44.9 million for the year ended June 30, 2005 compared to $9.6 million for the same period a year earlier, primarily as a result of a 161% increase in revenue and a 134% increase in non cash depletion expense. Our net cash used in investing activities increased by 24% to $183.9 million for the year ended June 30, 2005 compared to $148.4 million for the same period a year earlier. The increase in cash used for investing activity can be attributed to the expansion of our drilling programs in both the Rocky Mountain and Gulf Coast regions along with additional drilling rig acquisitions. Cash flow from financing was $139.2 million for the year ended June 30, 2005 which was consistent with $138.6 for the same period the prior year. During fiscal 2005, we financed our operations primarily with debt. On March 15, 2005, we issued 7% senior unsecured notes for an aggregate amount of $150.0 million. During fiscal 2004, we financed our operations with the issuance of $98.0 million in equity and an increase in our bank credit facility.

Capital and Exploration Expenditures and Financing

Our capital and exploration expenditures and sources of financing for the six months ended December 31, 2005 and years ended June 30, 2005, 2004 and 2003 are as follows:

	Six Months Ended December 31,	Year Ended June 30,		
	2005	2005	2004	2003
CAPITAL AND EXPLORATION EXPENDITURES:		(In thousands)		
Acquisitions:				
Savant Acquisition	$ 85,000	$ -	$ -	$ -
Manti	-	59,700	-	-
Columbia River Basin	-	18,255	-	-
Washington, County South and North Tongue	828	10,571	30,406	-
Sacramento Basin	-	10,400	-	-
Karnes County, Texas	-	5,000	-	-
Alpine Resources	-	-	120,655	-
Padgett	-	-	-	9,631
Other	7,904	2,718	-	-
Other development costs	86,871	102,216	37,969	8,468
Drilling and trucking companies	25,733	32,690	3,965	-
Exploration costs	3,411	6,155	2,406	140
	$ 209,747	$ 247,705	$ 195,401	$ 18,239
FINANCING SOURCES:				
Cash flow provided by operating activities	$ 26,226	$ 44,862	$ 9,623	$ 7,999
Stock issued for cash upon exercised options	1,166	132	3,563	975
Stock issued for cash, net	95,026	-	97,902	-
Net long-term borrowings	28,715	139,051	37,157	6,921
Proceeds from sale of oil and gas properties	34,178	18,721	10,787	850
Other	2,566	14,863	(721)	139
	$ 187,877	$ 217,629	$ 158,311	$ 16,884

We anticipate our capital and exploration expenditures to range between $150.0 and $195.0 million for the year ended December 31, 2006. The timing of most of our capital expenditures is discretionary.

Sale of Oil and Gas Properties - Discontinued Operations

On August 19, 2004, we completed the sale of our interests in five fields in Louisiana and South Texas previously acquired in the Alpine acquisition for $18.7 million, net of commission. We paid $8.8 million on our credit facility balance from the sale of these properties. No gain or loss was recognized on this transaction.

On September 2, 2005, we completed the sale of our interest in the Deerlick Field located in Tuscaloosa, Alabama, for net cash proceeds of $28.9 million and an effective date of July 1, 2005. We recorded a gain on sale of oil and gas properties of approximately $10.2 million. Revenues from these oil and gas properties were approximately $1.3 million, $4.9 million, $3.3 million and $3.0 million for the six months ended December 31, 2005 and the years ended June 30, 2005, 2004 and 2003, respectively.

During October 2005, we sold at auction our interest in several non-strategic fields for proceeds of $5.3 million and a gain of $1.6 million.

Contractual and Long-Term Debt Obligations

Contractual Obligations at December 31, 2005	Payments Due by Period Less than 1 year	2-3 Years	4-5 Years (In thousands)	After 5 Years	Total
7% Senior unsecured notes	$ -	$ -	$ -	$ 150,000	$ 150,000
Interest on 7% Senior unsecured notes	10,500	21,000	21,000	46,783	99,283
Credit facility	-	64,270	-	-	64,270
Term loan – DHS	7,000	14,000	14,000	-	35,000
Abandonment retirement obligation	466	340	478	6,438	7,722
Derivative liability	12,376	5,847	-	-	18,223
Operating leases	1,843	3,691	2,920	4,100	12,554
Other debt obligations	73	80	-	-	153
Total contractual cash obligations	$ 32,258	$109,228	$ 38,398	$207,321	$ 387,205

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 semiannually on April 1 and October 1 and mature in 2015. The net proceeds were used to refinance debt outstanding under our credit facility which included the amount required to acquire the Manti properties. The notes were issued at 99.50% of par and the associated discount is being amortized to interest expense over the term of the notes. The indenture governing the 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.

Credit Facility

At December 31, 2005, our $200.0 million credit facility had an available borrowing base of approximately $75.0 million and $64.3 million outstanding. The temporary reduction in available borrowing base was established until certain drilling results were attained. We anticipate our available borrowing base to increase with future drilling success. The facility has variable interest rates based upon the ratio of outstanding debt to the borrowing base. Rates vary between prime + .25% and 1.00% for base rate loans and between Libor + 1.5% and 2.25% for Eurodollar loans. The facility is collateralized by substantially all of our oil and gas properties. Currently, we are required to meet certain financial covenants which include a current ratio of 1 to 1, net of derivative instruments, and a consolidated debt to EBITDAX (Earnings before interest, taxes, depreciation, amortization and exploration) of less than 3.5 to 1. The financial covenants only include subsidiaries which we own 100%. At December 31, 2005, the Company was not in compliance with its quarterly debt covenants and restrictions, but obtained a waiver from the banks for the quarter ended December 31, 2005. In addition, the credit agreement was amended to exclude the quarter ended March 31, 2006 from the current ratio requirement.

Subsequent determinations of the borrowing base will be made by the lending banks at least semi-annually on April 1 and October 1 of each year, or as special re-determinations. 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 (1) to make a mandatory payment of principal to reduce our outstanding indebtedness so that it would not exceed our borrowing base, and (2) to eliminate the deficiency by making three equal monthly principal payments, (3) within 90 days, to provide additional collateral for consideration to eliminate the deficiency or (4) to 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 our credit facility.

The credit facility 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 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 will 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 will 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, oil and gas inventory, and certain bank accounts and proceeds.

Term Loan - DHS

On September 30, 2005, DHS completed a financing arrangement with Guggenheim Corporate Funding, LLC ("Guggenheim") for $35.0 million due September 30, 2010, with principal and interest payments due on the first calendar day of each quarter. The note bears interest at the Prime Rate plus 3.0%, or 10.0% at December 31, 2005. The note contains quarterly financial covenants applied to DHS on a stand-alone basis including a maximum leverage ratio of 2.5 to 1 (declining to 2.0 to 1.0 at June 30, 2006), a minimum current ratio of 1.25 to 1.0 and a minimum interest coverage ratio of 2.50 to 1, each as defined in the agreement. At December 31, 2005, DHS was not in compliance with its quarterly debt covenants and restrictions; however, on January 6, 2006 the note was amended with revised covenants effective as of December 31, 2005.

Other Contractual Obligations

Our abandonment retirement obligation arises from the plugging and abandonment liabilities for our oil and gas wells. The majority of this obligation will not occur over the next five years.

We lease our corporate office in Denver, Colorado under an operating lease which will expire in fiscal 2015. Our average yearly payments approximate $864,000 over the life of the lease. We have additional operating lease commitments which represent office equipment leases and short term debt obligations primarily relating to field vehicles and equipment.

Derivative instruments represent the net estimated unrealized losses for our oil and gas hedges at December 31, 2005. The ultimate settlement amounts of these hedges are unknown because they are subject to continuing market risk.

The following table summarizes our derivative contracts outstanding at December 31, 2005:

Commodity	Volume	Price Floor / Price Ceiling	Term	Index	Unrealized losses at December 31, 2005 (In thousands)
Contracts that qualify for hedge accounting					
Crude oil	40,000 Bbls / month	$ 40.00 / $ 50.34	July '05 - June '06	NYMEX-WTI	$ 3,002
Crude oil	10,000 Bbls / month	$ 45.00 / $ 56.90	July '05 - June '06	NYMEX-WTI	416
Crude oil	25,000 Bbls / month	$ 35.00 / $ 61.80	July '06 - June '07	NYMEX-WTI	2,445
Contracts that do not qualify for hedge accounting					
Natural gas	10,000 MMBtu / day	$ 5.00 / $ 9.60	July '05 - June '06	NYMEX-H HUB	2,828
Natural gas	3,000 MMBtu / day	$ 6.00 / $ 9.35	July '05 - June '06	NYMEX-H HUB	945
Natural gas	13,000 MMBtu / day	$ 5.00 / $ 10.20	July '06 - June '07	NYMEX-H HUB	8,586
					$ 18,222

The fair value of our derivative instruments obligation was $18.2 million at December 31, 2005 and $9.2 million on February 28, 2006.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations were based upon 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 1 to our consolidated financial statements. In response to SEC Release No. 33-8040, "Cautionary Advice

Regarding Disclosure About Critical Accounting Policies," 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 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 incurred to select development locations within an oil and gas field is typically considered a development cost and 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, 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.

Impairment of Gas and Oil Properties

We review our oil and gas properties for impairment 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 factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, 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.

Commodity Derivative Instruments and Hedging Activities

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

All derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. For qualifying fair value hedges, the gain or loss on the derivative is offset by related results of the hedged item in the income statement. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as other expense or income in the consolidated statement of operations.

Asset Retirement Obligation

We account for our asset retirement obligations under SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for retirement obligations of acquired assets. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on July 1, 2002 and recorded a cumulative effect of a change in accounting principle on prior years related to the depreciation and accretion expense that would have been reported had the fair value of the asset retirement obligations, and corresponding increase in the carrying amount of the related long-lived assets, been recorded when incurred. The Company's asset retirement obligations arise from the plugging and abandonment liabilities for its oil and gas wells.

In March 2005, the FASB issued FASB Interpretation 47 ("FIN 47"), an interpretation of SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143"). FIN 47 clarifies the term "conditional asset retirement obligation" as it is used in SFAS No. 143. The Company applied the guidance of FIN 47 beginning July 1, 2005 resulting in no impact on its financial statements.

Deferred Tax Asset Valuation Allowance

The Company follows SFAS No. 109, "Accounting for Income Taxes," to account for its deferred tax assets and liabilities. Under SFAS No. 109, deferred tax assets and liabilities are recognized for the estimated future tax effects attributable to temporary differences and carry forwards. 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, the Company maintains a valuation allowance against a portion of its deferred tax assets. The Company will continue to monitor facts and circumstances in its reassessment of the likelihood that operating loss carryforwards and other deferred tax attributes will be utilized prior to their expiration. As a result, the Company 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.

Recently Issued Accounting Standards and Pronouncements

In May 2005, the Financial Accounting Standards Board ("FASB") issued SFAS No. 154, Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3 ("Statement 154"). SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that a change in depreciation, amortization, or depletion method for long-lived, non-financial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The implementation of FAS 154 is not expected to have a material impact on our condensed consolidated results of operations, financial position or cash flows.

In April 2005, the FASB issued Staff Position 19-1, ("FSP 19-1") "Accounting for Suspended Well Costs". FSP 19-1 provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved and specifies that drilling costs for completed exploratory wells should be expensed if the related reserves cannot be classified as proved within one year unless certain criteria are met. FSP 19-1 is effective for all reporting periods beginning after April 4, 2005, and accordingly, the Company adopted FSP 19-1 on July 1, 2005.

Quantitative and Qualitative Disclosures about Market Risk

Market risk is the potential loss arising from adverse changes in market rates and prices, such as foreign currency exchange and interest rates and commodity prices. We do not use financial instruments to any degree to manage foreign currency exchange and interest rate risks and do not hold or issue financial instruments to any degree for trading purposes. All of our revenue and related receivables are payable in U.S. dollars.

Market Rate and Price Risk

We began to hedge a portion of our oil and gas production using swap and collar agreements. The purpose of these hedge agreements is to provide a measure of stability to our cash flow in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk.

The current derivative contracts cover approximately 32% of our estimated 2006 production. Assuming production and the percent of oil and gas sold remained unchanged from the six months ended December 31, 2005, a hypothetical 10% decline in the average market price the Company realized during the six months ended December 31, 2005 on unhedged production would reduce the Company's oil and natural gas revenues by approximately $6.2 million on an annual basis.

Interest Rate Risk

We were subject to interest rate risk on $99.3 million of variable rate debt obligations at December 31, 2005. The annual effect of a ten percent change in interest rates would be approximately $782,000. The interest rate on these variable rate debt obligations approximates current market rates as of December 31, 2005.

FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors
Delta Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Delta Petroleum Corporation and subsidiaries as of December 31, 2005 and June 30, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for the six months ended December 31, 2005 and years ended June 30, 2005, 2004 and 2003. 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, 2005 and June 30, 2005 and 2004, and the results of their operations and their cash flows for the six months ended December 31, 2005 and each of the years ended June 30, 2005, 2004 and 2003, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2005, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of the Sponsoring Organizations of the Treadway Commission, and our report dated March 9, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

As discussed in footnote 2 to the consolidated financial statements, Delta Petroleum Corporation adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* as of July 1, 2002.

As also discussed in footnote 2 to the consolidated financial statements, Delta Petroleum Corporation adopted Statement of Financial Accounting Standards No. 123(R), *Share Based Payment,* as of July 1, 2005.

KPMG
Denver, Colorado
March 9, 2006

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2005	June 30, 2005	June 30, 2004
		(In thousands)	
ASSETS			
Current assets:			
Cash and cash equivalents	$ 5,519	$ 2,241	$ 2,078
Marketable securities available for sale	-	1,764	912
Assets held for sale	19,215	-	-
Trade accounts receivable, net of allowance for doubtful accounts, of $100, $100, and $50, respectively	22,202	10,512	9,092
Prepaid assets	3,442	2,980	1,136
Inventory	3,285	5,062	1,350
Deferred tax asset	5,237	2,676	-
Derivative instruments	89	378	-
Other current assets	2,600	1,421	385
Total current assets	61,589	27,034	14,953
Property and equipment:			
Oil and gas properties, successful efforts method of accounting:			
Unproved	167,143	101,935	49,747
Proved	438,666	365,306	223,145
Drilling and trucking equipment, including deposits on equipment of $5,000, $7,500 and zero, respectively	64,129	40,031	3,965
Other	12,809	10,412	1,147
Total property and equipment	682,747	517,684	278,004
Less accumulated depreciation and depletion	(61,593)	(44,134)	(21,665)
Net property and equipment	621,154	473,550	256,339
Long-term assets:			
Investment in LNG project	1,022	1,022	1,022
Deferred financing costs	5,291	5,825	131
Deferred tax assets	1,322	4,887	-
Derivative instruments	163	469	-
Goodwill	2,341	-	-
Other long-term assets	511	196	259
Total long-term assets	10,650	12,399	1,412
Total assets	$ 693,393	$ 512,983	$ 272,704
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Current portion of long-term debt	$ 7,073	$ 3,477	$ 109
Accounts payable	67,772	38,151	12,326
Other accrued liabilities	19,462	5,281	1,855
Derivative instruments	12,465	7,241	-
Total current liabilities	106,772	54,150	14,290
Long-term liabilities:			
7% Senior notes, unsecured	149,309	149,272	-
Credit facility	64,270	66,500	69,375
Term loan – DHS	28,000	-	-
Asset retirement obligation	3,002	2,975	2,542
Derivative liabilities	6,009	3,620	-
Other debt, net	80	229	255
Total long-term liabilities	250,670	222,596	72,172
Minority interest	15,496	14,614	245
Commitments and contingencies			
Stockholders' equity:			
Preferred stock, $.10 par value: authorized 3,000,000 shares, none issued	-	-	-
Common stock, $.01 par value; authorized 300,000,000 shares, issued 47,825,000 shares at December 31, 2005, 42,017,000 shares at June 30, 2005 and 38,447,000 shares at June 30, 2004	478	420	384
Additional paid-in capital	333,054	235,300	207,811
Unearned compensation	-	(1,382)	-
Accumulated other comprehensive (loss) income	(4,997)	(5,225)	342
Accumulated deficit	(8,080)	(7,490)	(22,540)
Total stockholders' equity	320,455	221,623	185,997
Total liabilities and stockholders' equity	$ 693,393	$ 512,983	$ 272,704

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Six Months Ended December 31,	Years Ended June 30,		
	2005	2005	2004	2003
	(In thousands, except per share amounts)			
Revenue:				
Oil and gas sales	$ 60,656	$ 90,871	$ 37,226	$ 22,576
Contract drilling and trucking fees	9,096	4,796	-	-
Realized loss on derivative instruments, net	(7,978)	(960)	(859)	(1,858)
Total revenue	61,774	94,707	36,367	20,718
Operating expenses:				
Lease operating expense	9,434	15,566	7,530	6,966
Transportation expense	829	575	259	230
Production taxes	3,541	6,128	1,978	1,214
Depreciation, depletion, accretion and amortization – oil and gas	17,577	21,682	9,900	4,999
Depreciation and amortization – drilling and trucking	2,847	1,525	14	-
Exploration expense	3,411	6,155	2,406	140
Dry hole costs	4,073	2,771	2,132	537
Drilling and trucking operations	5,821	4,666	232	-
Professional fees	2,264	2,010	1,174	842
General and administrative	14,227	14,920	6,875	4,295
Total operating expenses	64,024	75,998	32,500	19,223
Operating income (loss)	(2,250)	18,709	3,867	1,495
Other income and (expense):				
Other income (expense)	173	(492)	122	31
Gain on sale of marketable securities, net	1,194	-	-	-
Unrealized loss on derivative contracts, net	(9,872)	-	-	-
Minority interest	(688)	1,017	70	-
Interest and financing costs	(9,075)	(7,958)	(1,762)	(1,767)
Total other expense	(18,268)	(7,433)	(1,570)	(1,736)
Income (loss) from continuing operations before income taxes and discontinued operations	(20,518)	11,276	2,297	(241)
Income tax benefit	7,639	3,325	-	-
Income (loss) from continuing operations	(12,879)	14,601	2,297	(241)
Discontinued operations:				
Income from discontinued operations of properties sold, net of tax	501	449	872	1,241
Gain on sale of oil and gas properties, net of tax	11,788	-	1,887	277
Cumulative effect of change in accounting principle, net of tax	-	-	-	(20)
Net income (loss)	$ (590)	$ 15,050	$ 5,056	$ 1,257
Basic income (loss) per common share:				
Income (loss) from continuing operations	$ (.29)	$ .36	$ .09	$ (.01)
Discontinued operations	.28	.01	.10	.06
Cumulative effect of change in accounting principle, net of tax	-	-	-	*
Net income (loss)	$ (.01)	$ .37	$ .19	$ .05
Diluted income (loss) per common share:				
Income (loss) from continuing operations	$ (.29)	$ .36	$ .08	$ (.01)
Discontinued operations	.28	.01	.09	.06
Cumulative effect of change in accounting principle	-	-	-	*
Net income (loss)	$ (.01)	$ .36	$ .17	$ .05

* Less than $.01 per common share

See accompanying notes to consolidated financial statements.

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

(In thousands, except per share amounts)

	Common stock Shares	Common stock Amount	Additional paid-in capital	Put Option on Delta Stock	Accumulated other comprehensive income/(loss)	Comprehensive income (loss)	Unearned Compensation	Accumulated deficit	Total
Balance, July 1, 2002	22,618	$ 226	$ 76,514	$(2,886)	$ (85)			$ (28,853)	$44,916
Comprehensive income:									
Net income	-	-	-	-	-	$ 1,257		1,257	1,257
Other comprehensive income, net of tax									
Change in fair value of derivative hedging instruments	-	-	-	-	(468)	(468)		-	(468)
Unrealized gain on marketable securities, net	-	-	-	-	177	177		-	177
Comprehensive income						$ 966			
Stock options granted as compensation	-	-	124	-	-			-	124
Put option on Delta stock	-	-	(2,886)	2,886	-			-	-
Shares issued for oil and gas properties	200	2	920	-	-			-	922
Shares issued for cash upon exercise of options	468	5	970	-	-			-	975
Balance, June 30, 2003	23,286	233	75,642	-	(376)			(27,596)	47,903
Comprehensive income:									
Net income	-	-	-	-	-	$ 5,056		5,056	5,056
Other comprehensive gain, net of tax									
Change in fair value of derivative hedging instruments	-	-	-	-	468	468		-	468
Unrealized gain on marketable securities, net	-	-	-	-	250	250		-	250
Comprehensive income						$ 5,774			
Stock options granted as compensation	-	-	329	-	-			-	329
Shares issued for cash, net	10,000	100	97,802	-	-			-	97,902
Shares issued for oil and gas properties	3,728	37	30,489	-	-			-	30,526
Shares issued for cash upon exercise of options	1,433	14	3,549	-	-			-	3,563
Balance, June 30, 2004	38,447	384	207,811	-	342			(22,540)	185,997
Comprehensive income:									
Net income	-	-	-	-	-	$ 15,050		15,050	15,050
Other comprehensive gain, net of tax									
Change in fair value of derivative hedging *instruments, net of tax benefit of $3,722*	-	-	-	-	(5,961)	(5,961)		-	(5,961)
Unrealized gain on marketable securities, net of tax expense of $458	-	-	-	-	394	394		-	394
Comprehensive income						$ 9,483			
Shares issued for oil and gas properties	1,571	16	22,175	-	-			-	22,191
Shares issued for drilling equipment	131	1	1,892	-	-			-	1,893
Shares issued for cash upon exercise of options, net	1,793	18	114	-	-			-	132
Tax benefit on options exercised	-	-	1,255	-	-			-	1,255
Issuance of options below market	-	-	346	-	-		$ (346)	-	-
Issuance of restricted options	75	1	1,707	-	-		(1,708)	-	-
Amortization of unearned option compensation	-	-	-	-	-		672	-	672
Balance, June 30, 2005	42,017	420	235,300	-	(5,225)		(1,382)	(7,490)	221,623
Comprehensive income:									
Net loss	-	-	-	-	-	$ (590)		(590)	(590)
Other comprehensive transactions, net of tax									
Realized gain on equity securities sold, net of tax expense of $458	-	-	-	-	(736)	(736)		-	(736)
Hedging loss reclassified to income upon settlement, net of tax benefit of $1,733	-	-	-	-	2,398	2,398		-	2,398
Change in fair value of derivative hedging instruments, net of tax benefit of $1,036	-	-	-	-	(1,434)	(1,434)		-	(1,434)
Comprehensive income (loss)						$ (362)			
Shares issued for oil and gas properties	50	1	827	-	-			-	828
Shares issued for cash, net of offering costs	5,405	54	94,917	-	-			-	94,971
Shares issued for cash upon exercise of options	200	2	623	-	-			-	625
Reclassification of unearned compensation upon adoption of SFAS 123R	-	-	(1,382)	-	-		1,382	-	-
Issuance and amortization of unearned compensation	153	1	766	-	-		-	-	767
Compensation on options vested	-	-	2,003	-	-		-	-	2003
Balance, December 31, 2005	47,825	$ 478	$ 333,054	$ -	$ (4,997)		$ -	$ (8,080)	$320,455

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended December 31, 2005	Years Ended June 30, 2005	2004	2003
		(In thousands)		
Cash flows from operating activities:				
Net Income (loss)	$ (590)	$ 15,050	$ 5,056	$ 1,257
Adjustments to reconcile net income (loss) to cash provided by operating activities:				
Depreciation, depletion, and amortization – oil and gas	17,481	21,429	9,840	4,942
Depreciation and amortization – drilling and trucking	2,847	1,525	14	-
Depreciation, depletion, and amortization – discontinued operations	91	208	328	791
Accretion of abandonment obligation	96	253	60	57
Stock option and restricted stock compensation	2,770	672	329	124
Amortization of deferred financing costs	669	858	324	456
Unrealized loss on derivative contracts	9,872	331	-	-
Minority Interest	688	(1,017)	(70)	-
Deferred tax benefit	(7,336)	(3,045)	-	-
Dry hole costs and impairment	1,872	-	-	-
Gain on sale of marketable securities	(1,194)	-	-	-
Gain on sale of oil and gas properties – discontinued operations	(11,788)	-	(1,887)	(277)
Other	140	394	-	20
Net changes in operating assets and liabilities:				
Increase in trade accounts receivable	(10,454)	(1,586)	(4,878)	(101)
(Increase) decrease in prepaid assets	(457)	(1,844)	(372)	21
(Increase) decrease in inventory	947	(5,062)	(1,350)	-
(Increase) decrease in other current assets	(1,968)	(225)	205	(78)
Increase in accounts payable trade	6,688	14,004	1,361	116
Increase in other accrued liabilities	14,505	2,917	663	671
Net cash provided by operating activities	24,879	44,862	9,623	7,999
Cash flows from investing activities:				
Additions to property and equipment,	(157,519)	(186,669)	(158,504)	(15,637)
Additions to drilling and trucking equipment,	(21,828)	(30,797)	-	-
Acquisition of trucking company, net of cash acquired	(3,905)	-	-	-
Proceeds from sale of oil and gas properties	34,178	18,721	10,787	850
Proceeds from sale of marketable securities	1,764	-	-	-
Minority interest contributions, net	-	14,800	315	-
Payment on investment transaction	-	-	(1,022)	-
(Increase) decrease in long term assets	802	63	(14)	139
Net cash used in investing activities	(146,508)	(183,882)	(148,438)	(14,648)
Cash flows from financing activities:				
Stock issued for cash upon exercise of options	1,166	132	3,563	975
Stock issued for cash, net	94,971	-	97,902	-
Stock issued for cash, DHS	55	-	-	-
Proceeds from borrowings	72,998	361,016	69,979	9,000
Payment of financing fees	(502)	(7,370)	(368)	(354)
Repayment of borrowings	(43,781)	(214,595)	(32,454)	(1,725)
Net cash provided by financing activities	124,907	139,183	138,622	7,896
Net increase (decrease) in cash and cash equivalents	3,278	163	(193)	1,247
Cash at beginning of period	2,241	2,078	2,271	1,024
Cash at end of period	$ 5,519	$ 2,241	$ 2,078	$ 2,271
Supplemental cash flow information:				
Cash paid for interest and financing costs	$ 8,149	$ 11,420	$ 1,818	$ 1,312
Non-cash financing activities:				
Common stock issued for the purchase of oil and gas properties	$ 828	$ 22,191	$ 30,526	$ 922
Common stock issued for the purchase of drilling equipment	$ -	$ 1,893	$ -	$ -

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, through a series of transactions in 2004 and 2005, owns a 49.5% interest in DHS Drilling Company ("DHS"), an affiliated Colorado corporation that is headquartered in Casper, Wyoming. Delta has the right to use all of the rigs on a priority basis, although approximately half are currently working for third party operators. DHS also owns 100% of Chapman Trucking which was acquired in November 2005 and which ensures DHS rig mobility.

At December 31, 2005, 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 owns undeveloped oil and gas properties in federal units offshore California, near Santa Barbara.

On February 19, 2002, the Company acquired 100% of the outstanding shares of Piper Petroleum Company ("Piper"), a privately owned oil and gas company headquartered in Fort Worth, Texas. Piper was merged into a subsidiary wholly owned by Delta.

In late 2005 we transferred our ownership in approximately 64,000 net acres of non-operated interests in the Columbia River Basin to CRB Partners, LLC, which originally was a wholly-owned subsidiary ("CRBP"). Subsequent to year-end, we sold a minority interest in CRBP. We have retained the majority ownership in, and are the manager of, CRBP. This sale did not involve any of our operated 100% leasehold of approximately 332,000 net acres in the Columbia River Basin.

(2) Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of Delta, Amber, Piper, CRBP and DHS (collectively, the "Company"). All inter-company balances and transactions have been eliminated in consolidation. As Amber is in a net stockholders' deficit position for the periods presented, the Company has recognized 100% of Amber's earnings/losses for all periods. The Company has no interests in any unconsolidated entities other than its investment in a liquid natural gas LLC which is recorded at its cost, nor does it have any off-balance sheet financing arrangements (other than operating leases) or any unconsolidated special purpose entities.

Certain of the Company's oil and gas activities are conducted through partnerships and joint ventures. The Company includes its proportionate share of assets, liabilities, revenues and expenses from these entities in its consolidated financial statements.

Certain reclassifications have been made to amounts reported in previous years to conform to the 2005 presentation. Such reclassifications had no effect on net income.

(2) Summary of Significant Accounting Policies, Continued

Fiscal Year Change

On September 14, 2005, the Board of Directors approved the change of the fiscal year end from June 30 to December 31, effective December 31, 2005. This Form 10-K is a transitional report, and includes information for the six-month transitional period ended December 31, 2005 and for the twelve-month periods ended June 30, 2005, 2004 and 2003. The unaudited financial information for the six-month period ended December 31, 2004 is as follows:

	Six Months Ended December 31, 2004 (In thousands, except per share data)
Total Revenues	$ 39,864
Operating Income	10,095
Income from continuing operations before income taxes and discontinued operations	8,025
Net Income	8,754
Net income per common share:	
Basic	$ .22
Diluted	$ .21

Cash Equivalents

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

Marketable Securities

The Company classifies its investment securities as available-for-sale securities. Pursuant to Statement of Financial Accounting Standards ("SFAS") No. 115 (SFAS 115), such securities are measured at fair market value in the financial statements with unrealized gains or losses recorded in other comprehensive income. At the time securities are sold or otherwise disposed of, gains or losses are included in earnings. During the six months ended December 31, 2005, the Company sold its investments as shown below.

	Cost	Realized Gain (Loss)	Proceeds From Sale
		(In thousands)	
December 31, 2005			
Bion Environmental Technologies, Inc.	$ 152	$ (140)	$ 12
Tipperary Oil & Gas Company	418	1,334	1,752
	$ 570	$ 1,194	$ 1,764

(2) Summary of Significant Accounting Policies, Continued

	Cost	Unrealized Gain (Loss)	Estimated Market Value
		(In thousands)	
June 30, 2005			
Bion Environmental Technologies, Inc.	$ 152	$ (140)	$ 12
Tipperary Oil & Gas Company	418	1,334	1,752
	$ 570	$ 1,194	$ 1,764
June 30, 2004			
Bion Environmental Technologies, Inc.	$ 152	$ (138)	$ 14
Tipperary Oil & Gas Company	418	480	898
	$ 570	$ 342	$ 912

Assets Held for Sale

Assets held for sale as of December 31, 2005 represent the cost basis related to the 427,000 gross acres (64,000 net acres) of non-operated interests in the Columbia River Basin that were transferred during December 2005 to a newly created wholly owned subsidiary, CRB Partners, LLC. In January 2006, Delta sold a minority interest in CRB Partners, LLC to a small group of investors. The Company expects to record a gain of during the first quarter of 2006 as a result of closing the transaction.

Inventories

Inventories consist of pipe, other production equipment and natural gas placed in storage. Inventories are stated at the lower of cost (principally first-in, first-out) or estimated net realizable value.

Minority Interest

Minority interest represents the 50.5% (45% for Chesapeake Energy Corporation, 5.5% for DHS executive officers and management) investors of DHS Drilling Company at December 31, 2005 and June 30, 2005. Prior to forming DHS, the Company owned a 50% interest in Big Dog Drilling Co., LLC ("Big Dog") and a 50% interest in Shark Trucking Co., LLC ("Shark"). The remaining net assets of Big Dog were ultimately acquired and, together with the interest previously owned, were contributed to DHS.

Revenue Recognition

Oil and Gas

Revenues are recognized when title to the products transfer 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. To the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves, a receivable or liability is recognized. As of December 31, 2005 and June 30, 2005 and 2004, the Company's aggregate natural gas and crude oil imbalances were not material to its consolidated financial statements except for an imbalance acquired during fiscal 2005 which was collected during the six months ended December 31, 2005.

Drilling and Trucking

We earn our contract drilling revenues under daywork. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. The cost 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.

(2) Summary of Significant Accounting Policies, Continued

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 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 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.

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

Depreciation, depletion and amortization of property and equipment for the six months ended December 31, 2005 and the fiscal years ended June 30, 2005, 2004 and 2003 were \$20.4 million, \$23.2 million, \$9.9 million and \$5.0 million, respectively.

Drilling equipment and other property and equipment are recorded at cost or estimated fair value upon acquisition and depreciated on a component basis using the straight-line method over their estimated useful lives.

Impairment of Long-Lived Assets

Statement of Financial Accounting Standards No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144) requires that long-lived assets be 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. 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 in accordance with SFAS No. 144 are permanent and may not be restored in the future.

The Company assesses developed properties on an individual field basis for impairment on at least an annual basis. 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 such assessment, the Company recorded no impairment provision attributable to producing properties for the six months ended December 31, 2005 and the fiscal years ended June 30, 2005, 2004 and 2003.

(2) Summary of Significant Accounting Policies, Continued

For undeveloped 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 undeveloped 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 no impairment provision attributable to undeveloped properties for the years ended June 30, 2005, 2004 and 2003.

During the six months ended December 31, 2005, a dry hole was drilled on the Company's prospect located in Orange County, California. Based on drilling results and the Company's evaluation of the Prospect, the Company determined that it would not pursue development of the field and accordingly an impairment was recorded. Included in the Company's consolidated statement of operations for the six months ended December 31, 2005 are $2.0 million for the dry hole that was drilled and $1.3 million, included in exploration expenses, for the full impairment of the remaining leasehold costs related to the prospect.

Goodwill

Goodwill represents the excess of the cost of the acquisition of Chapman Trucking in November 2005 over the fair value of the assets acquired. For goodwill and intangible assets recorded in the financial statements, an impairment test will be performed at least annually in accordance with the provisions of SFAS No. 142.

Asset Retirement Obligations

In July 2001, the Financial Accounting Standards Board ("FASB") approved for issuance SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for retirement obligations of acquired assets. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on July 1, 2002 and recorded a cumulative effect of a change in accounting principle on prior years of $20,000, net of tax effects, related to the depreciation and accretion expense that would have been reported had the fair value of the asset retirement obligations, and corresponding increase in the carrying amount of the related long-lived assets, been recorded when incurred. 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. The following is a reconciliation of the Company's asset retirement obligations for the six months ended December 31, 2005 and fiscal years ended June 30, 2005 and 2004.

	Six Months Ended December 31, 2005	Years Ended June 30, 2005	Years Ended June 30, 2004
		(In thousands)	
Asset retirement obligation – beginning of period	$ 3,691	$ 2,647	$ 868
Accretion expense	96	253	60
Change in estimate	(19)	-	438
Obligations acquired	160	1,153	1,522
Obligations settled	-	-	(3)
Obligations on sold properties	(461)	(362)	(238)
Asset retirement obligation – end of period	3,467	3,691	2,647
Less: Current asset retirement obligation	(465)	(716)	(105)
Long-term asset retirement obligation	$ 3,002	$ 2,975	$ 2,542

In March 2005, the FASB issued FASB Interpretation 47 ("FIN 47"), an interpretation of SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143"). FIN 47 clarifies the term "conditional asset retirement obligation" as it is used in SFAS No. 143. The Company applied the guidance of FIN 47 beginning July 1, 2005 resulting in no impact on its financial statements.

(2) Summary of Significant Accounting Policies, Continued

Comprehensive Income (Loss)

Comprehensive income (loss) includes all changes in equity during a period. The components of comprehensive income (loss) for the six months ended December 31, 2005 and fiscal years ended June 30, 2005, 2004 and 2003 are as follows (in thousands):

	Six Months Ended December 31, 2005	Years Ended June 30, 2005	2004	2003
Net income (loss)	$ (590)	15,050	5,056	1,257
Other comprehensive income (transactions):				
Realized gain on equity securities sold, net of tax benefit of $458	(736)	-	-	-
Unrealized gain on marketable securities, net of tax expense of zero, $458, zero, and zero, respectively	-	394	250	177
Hedging instruments reclassified to income upon settlement, net of tax benefit of $1,733	2,398	-	-	-
Change in fair value of derivative hedging instruments, net of tax benefit of $1,036, $3,722, zero, and zero, respectively	(1,434)	(5,961)	468	(468)
Comprehensive income (loss)	$ (362)	$ 9,483	$ 5,774	$ 966

Financial Instruments

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents and accounts receivable. The Company's cash equivalents are cash investments funds that are placed with major financial institutions. The Company manages and controls market and credit risk through established formal internal control procedures, which are reviewed on an ongoing basis. The Company attempts to minimize credit risk exposure to purchasers of the Company's oil and natural gas through formal credit policies, monitoring procedures, and letters of credit.

The Company used various assumptions and methods in estimating fair value disclosures for financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair market value due to the short maturity of these instruments. The carrying amount of the Company's credit facility approximated fair value because the interest rates on the credit facility are variable. The fair value of long-term debt was estimated based on quoted market prices. The fair values of derivative instruments were estimated based on discounted future net cash flows.

Accounting and reporting standards require that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. Those standards also require that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of Other Comprehensive Income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings.

(2) Summary of Significant Accounting Policies, Continued

Stock Option Plans

The Company previously accounted for its stock option plans in accordance with the provisions of Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations. As such, compensation expense was recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price.

In December 2004, SFAS No. 123 (Revised 2004), "Share Based Payment" ("SFAS No. 123R") was issued, which now requires the Company to recognize the grant-date fair value of stock options and other equity based compensation issued to employees in the statement of operations. The cost of share based payments is recognized over the period the employee provides service. The Company adopted SFAS No. 123R effective July 1, 2005 using the modified prospective method and recognized compensation expense related to stock options of $2.0 million, relating to employee provided services during the six months ended December 31, 2005.

For fiscal years prior to the adoption of SFAS No. 123R, had compensation cost for the Company's stock-based compensation plan been determined using the fair value of the options at the grant date, the Company's net income for the fiscal years ended June 30, 2005, 2004 and 2003 on a pro forma basis would have been as follows:

	Years Ended June 30,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Net income (loss)	$ 15,050	$ 5,056	$ 1,257
Equity compensation booked	306	-	-
FAS 123 compensation effect	(2,759)	(4,316)	(209)
Pro forma net income after FAS 123 implementation	$ 12,597	$ 740	$ 1,048
Pro forma income per common share:			
Basic	$ .31	$ .03	$ .05
Diluted	$ .30	$ .02	$ .04

Income Taxes

The Company uses the asset and liability method of accounting for income taxes as set forth in Statement of Financial Accounting Standards No. 109 (SFAS No. 109), "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. Under SFAS No. 109, 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.

(2) Summary of Significant Accounting Policies, Continued

Earnings (Loss) per Common Share

Basic earnings (loss) per share is computed by dividing net earnings (loss) attributed to common stock by the weighted average number of common shares outstanding during each period, excluding treasury shares. Diluted earnings (loss) per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of convertible preferred stock, stock options and warrants.

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 impact oil and gas reserves, bad debts, depletion and impairment of oil and gas properties, marketable securities, income taxes, derivatives, asset retirement obligations, contingencies and litigation accruals. Actual results could differ from these estimates.

Recently Issued Accounting Standards and Pronouncements

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3* ("Statement 154"). SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principles, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that a change in depreciation, amortization, or depletion method for long-lived, non-financial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The implementation of FAS 154 is not expected to have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In April 2005, the Financial Accounting Standards Board ("FASB") issued Staff Position 19-1, ("FSP 19-1") "Accounting for Suspended Well Costs." FSP 19-1 provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved and specifies that drilling costs for completed exploratory wells should be expensed if the related reserves cannot be classified as proved within one year unless certain criteria are met. FSP 19-1 is effective for all reporting periods beginning after April 4, 2005, and accordingly, the Company adopted FSP 19-1 on July 1, 2005. The following table reflects the net changes in capitalized exploratory well costs for six months ended December 31, 2005:

	Six Months Ended December 31,	Year Ended June 30,[2]		
	2005	2005	2004	2003
Balance at beginning of period, July 1,	$ 1,033	$ 10	$ -	$ -
Additions to capitalized exploratory well costs pending the determination of proved reserves	10,151	10,991	2,811	537
Reclassified to proved oil and gas properties based on the determination of proved reserves	(6,754)	(7,197)	(669)	-
Capitalized exploratory well costs charged to dry hole expense	(4,073)	(2,771)	(2,132)	(537)
Balance at end of period, December 31, and June 30,	$ 357	$ 1,033	$ 10	$ -

[1] The final FSP directs that costs suspended and expensed in the same period not be included in this analysis.

[2] Capitalized exploratory well costs for fiscal years ended December 31, 2005, 2004, and 2003, are presented based on the Company's previous accounting policy.

(3) Oil and Gas Properties

Unproved Undeveloped Offshore California Properties

The Company has direct and indirect ownership interests ranging from 2.49% to 100% in five unproved undeveloped offshore California oil and gas properties with aggregate carrying values of $11.0 million, $10.9 million and $10.8 million at December 31, 2005, June 30, 2005 and 2004, respectively. These property interests are located in proximity to existing producing federal offshore units near Santa Barbara, California and represent the right to explore for, develop and produce oil and gas from offshore federal lease units. Preliminary exploration efforts on these properties have occurred and the existence of substantial quantities of hydrocarbons has been indicated. The recovery of the Company's investment in these properties will require extensive exploration and development activities (and costs) that cannot proceed without certain regulatory approvals that have been delayed and is subject to other substantial risks and uncertainties.

The Company is not the designated operator of any of these properties but is an active participant in the ongoing activities of each property along with the designated operator and other interest owners. If the designated operator elected not to or was unable to continue as the operator, the other property interest owners would have the right to designate a new operator as well as share in additional property returns prior to the replaced operator being able to receive returns. Based on the Company's size, it would be difficult for the Company to proceed with exploration and development plans should other substantial interest owners elect not to proceed. However, to the best of its knowledge, the Company believes the designated operators and other major property interest owners intend to proceed with exploration and development plans under the terms and conditions of the operating agreement.

Even though the Company is not the designated operator of the properties and regulatory approvals have not been obtained, the Company believes exploration and development activities on these properties will occur and is committed to expend funds attributable to its interests in order to proceed with obtaining the approvals for the exploration and development activities.

Based on indications of levels of hydrocarbons present from drilling operations conducted in the past, the Company believes the fair value of its property interests are in excess of their carrying value at December 31, 2005, June 30, 2005 and June 30, 2004 and that no impairment in the carrying value has occurred. Should the required regulatory approvals not be obtained or plans for exploration and development of the properties not continue, the carrying value of the properties would likely be impaired and written off.

The forty undeveloped leases are located in the Offshore Santa Maria Basin off the coast of Santa Barbara and San Luis Obispo counties, and in the Santa Barbara Channel off Santa Barbara and Ventura counties. The ownership rights in each of these properties have been retained under various suspension notices issued by the Mineral Management Service (MMS) of the U.S. Federal Government whereby, as long as the owners of each property were progressing toward defined milestone objectives, the owners' rights with respect to the properties continue to be maintained. The issuance of the suspension notices has been necessitated by the numerous delays in the exploration and development process resulting from regulatory requirements imposed on the property owners by federal, state and local agencies.

On June 22, 2001, however, a Federal Court in the case of California v. Norton, et al. ruled that the MMS does not have the power to grant suspensions on the subject leases without first making a consistency determination under the Coastal Zone Management Act ("CZMA"), and ordered the MMS to set aside its approval of the suspensions of the Company's offshore leases and to direct suspensions for a time sufficient for the MMS to provide the State of California with the required consistency determination. The delays have prevented the property owners from submitting for approval an exploration plan on four of the properties. If and when plans are submitted for approval, they are subject to review for consistency with the CZMA, and by the MMS for other technical requirements.

(3) Oil and Gas Properties, Continued

As the ruling in the Norton case currently stands, the United States has made a consistency determination under the CZMA in accordance with the Court's order and the leases are still valid. If the leases are found not to be valid for some reason in the future, it would appear that the leases would become impaired even though the Company would undoubtedly proceed with its litigation. It is also possible that other events could occur that would cause the leases to become impaired, and the Company will continuously evaluate those factors as they occur.

None of these leases is currently impaired, but in the event that there is some future adverse ruling by the California Coastal Commission under the CZMA and the Company decides not to appeal such ruling to the Secretary of Commerce, or the Secretary of Commerce either refuses to hear the Company's appeal of any such ruling or ultimately makes an adverse determination, it is likely that some or all of these leases would become impaired and written off at that time.

Delta and its majority-owned subsidiary, Amber Resources Company of Colorado, are among twelve plaintiffs in a lawsuit that was filed in the United States Court of Federal Claims in Washington, D.C. alleging that the U.S. government has materially breached the terms of forty undeveloped federal leases, some of which are part of Delta's offshore California properties. The Complaint is based on allegations by the collective plaintiffs that the United States has materially breached the terms of certain of their offshore California leases by attempting to deviate significantly from the procedures and standards that were in effect when the leases were entered into, and by failing to carry out its own obligations relating to those leases in a timely and fair manner. More specifically, the plaintiffs have alleged that the judicial determination in the California v. Norton case, that a 1990 amendment to the Coastal Zone Management Act that required the government to make a consistency determination prior to granting lease suspension requests in 1999, constitutes a material change in the procedures and standards that were in effect when the leases were issued. The plaintiffs have also alleged that the United States has failed to afford them the timely and fair review of their lease suspension requests which has resulted in significant, continuing and material delays to their exploratory and development operations.

The suit seeks compensation for the lease bonuses and rentals paid to the Federal government, exploration costs and related expenses. The total amount claimed by all lessees for bonuses and rentals exceeds $1.2 billion, with additional amounts for exploration costs and related expenses. The company owns approximately 12% of the lease bonus costs that are the subject of the lawsuit. In addition, the Company's claim for exploration costs and related expenses will also be substantial. In the event, however, that Delta receives any proceeds as the result of such litigation, it will be obligated to pay a portion of any amount received by it to landowners and other owners of royalties and similar interests, to pay the litigation expenses and to fulfill certain pre-existing contractual commitments to third parties.

On November 15, 2005, the United States Court of Federal Claims issued a ruling in the suit granting the plaintiffs' motion for summary judgment as to liability and partial summary judgment as to damages with respect to thirty six of the forty total federal leases that are the subject of the litigation. The court's ruling also denied the United States' motion to dismiss and motion for summary judgment. The United States Court of Federal Claims ruled that the federal government's imposition of new and onerous requirements that stood as a significant obstacle to oil and gas development breached agreements that it made when it sold thirty six out of the total forty offshore California federal leases that are the subject of the litigation. The Court further ruled that the government must give back to the current lessees the more than $1.1 billion in lease bonuses it had received at the time of sale.

Delta and Amber are among the current lessees of the thirty six leases that are the subject of the ruling. Together with Amber, Delta's net share of the $1.1 billion award is approximately $121 million. The final ruling in the case will not be made until the Court addresses the plaintiffs' additional claims regarding the four additional leases, as well as their claims regarding the hundreds of millions of dollars that have been spent in the successful efforts to find oil and gas in the disputed lease area, and other matters.

(3) Oil and Gas Properties, Continued

The final ruling, including the ruling made on November 15, will be subject to appeal, and no payments will be made until all appeals have either been waived or exhausted.

Six Months Ended December 31, 2005 – Acquisitions

On September 29, 2005 the Company acquired an undivided 50% working interest in approximately 145,000 net undeveloped acres in the Columbia River Basin in Washington, and an interest in undeveloped acreage in the Piceance Basin in Colorado from Savant Resources, LLC ("Savant") for an aggregate purchase price of $85.0 million in cash. James Wallace, a director of Delta, owns approximately a 1.7% interest in Savant, and also serves as a director of Savant. The majority of the acquired acreage in the Columbia River Basin consolidated the Company's leasehold position at that time. Subsequent to the acquisition, Delta owned a 100% working interest in approximately 385,000 net acres. This acquisition included a small portion of acreage that is subject to an agreement with EnCana Oil & Gas (USA) Inc., whereby the Company has the right to convert an overriding royalty interest to a working interest at project payout. In the Piceance Basin, the Company acquired Savant's interest in an entity that owns a 25% interest in approximately 6,314 gross acres that is currently being developed. The acquisition was funded through the issuance of securities discussed in Footnote 6, Stockholders' Equity.

Fiscal 2005 - Acquisitions

On December 15, 2004, the Company entered into a purchase and sale agreement to acquire substantially all of the oil and gas assets owned by several entities related to Manti Resources, Inc., which was an unaffiliated, privately held Texas corporation ("Manti"). The adjusted purchase price of $59.7 million was paid in cash at the closing of the transaction, which occurred on January 21, 2005. The purchase price for the Manti properties was determined through arms-length negotiations. The purchase price was paid with increased borrowings on the Company's bank credit facility. Substantially all of the assets that were acquired from Manti have been pledged as collateral for the bank credit facility.

On June 29, 2004, the Company completed the acquisition of substantially all of the oil and gas assets owned by several entities controlled by Alpine Resources, Inc. ("Alpine") for $122.5 million, which was funded with $68.4 million in net proceeds that the Company received from a $72.0 million private placement of 6 million shares of its restricted common stock to institutional investors at a purchase price of $12.00 per share, and from borrowings of $54.1 million under its senior credit facility. On August 19, 2004 the Company sold a portion of these assets to Whiting Petroleum Corporation for $18.7 million in net proceeds. There was no gain or loss on the sale of these assets.

The following unaudited pro forma condensed consolidated statement of operations information assumes that the Manti and Alpine property acquisitions occurred as of July 1, 2003:

	Years Ended June 30,	
	2005	2004
	(In thousands)	
Oil and gas sales	$113,059	$ 86,272
Net earnings from continuing operations, net of tax	$ 19,142	$ 15,514
Net earnings from continuing operations per common share, net of tax:		
Basic	$ .47	$ .47
Diluted	$ .46	$ .44

(3) Oil and Gas Properties, Continued

The above unaudited condensed pro forma consolidated statements of operations information, based on the historical producing property operating results of Manti, Alpine and Delta, are not necessarily indicative of the results of operations if Delta would have acquired the Manti and Alpine properties at July 1, 2003.

On September 15, 2004, the Company acquired seven wells in Karnes County, Texas from an unrelated entity and an unrelated individual for $5.0 million in cash.

On July 1, 2004, the Company acquired certain interests in California's Sacramento Basin and a 7.5% reversionary working interest in the South Tongue interests in Washington County, Colorado from Edward Mike Davis, LLC, a greater than 5% stockholder, for 760,000 shares of the Company's common stock valued at $10.4 million using the average five-day closing price before and after the terms of the agreement were agreed upon and closed. The total acquisition cost was allocated $4.3 million to proved developed producing and $6.1 million to proved undeveloped.

On May 4, 2005, the Company purchased from an unrelated private company a 14.25% back-in working interest in approximately 427,000 acres in the Columbia River Basin for $18.2 million in cash. The acreage is in close proximity to many of its existing leasehold interests in the basin and includes a lease on which another operator is currently drilling. The interest acquired is a non-cost bearing interest with a back-in after project payout. The Company can, however, at any time and at its discretion, convert the interest to a cost-bearing working interest by paying its proportionate share of the costs incurred in the project.

Fiscal 2004 - Acquisitions

During fiscal 2004 the Company made other producing property acquisitions in North Dakota of approximately 2.4 Bcfe for a total consideration of $4.2 million through the issuance 773,500 shares of the Company's common stock.

During the period from September of 2003 through July of 2004 the Company completed a series of transactions with Edward Mike Davis and certain unrelated individuals which resulted in an acquisition of a producing property and approximately 360,000 acres of undeveloped properties in the Company's North and South Tongue prospects located in Washington and Yuma Counties, Colorado, and an interest in producing and non-producing properties located in Colusa, Orange and Los Angeles Counties, California. Through these acquisitions the Company obtained an aggregate of approximately 6 Bcfe in proved producing reserves and a significant drilling inventory for a total consideration of approximately $8.0 million in cash and 2,551,000 shares of the Company's common stock.

During fiscal 2004, the Company invested an aggregate of $1.0 million for a 6.25% interest as a member of Crystal Energy, LLC, which is an unaffiliated Delaware limited liability company that is currently in the process of attempting to obtain the rights to own and operate a liquid natural gas facility from Platform Grace, which is an existing platform located offshore California. If the limited liability company is successful in obtaining these rights, it intends to engage in the business of accepting and vaporizing liquid natural gas delivered by liquid natural gas tankers, transporting the vaporized liquid natural gas through proprietary gas pipelines and selling the vaporized natural gas to third party customers located in California. As of December 31, 2005, the limited liability company had not yet engaged in any revenue producing activities.

(3) Oil and Gas Properties, Continued

Discontinued Operations

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the results of operations and gain (loss) relating to the sale of the following property interests have been reflected as discontinued operations.

During October 2005, the Company sold its interest in various insignificant fields that were not strategic to the Company for proceeds of $5.3 million. The Company recorded a gain of $1.6 million, net of a $1.0 million provision for income taxes.

On September 2, 2005, the Company completed the sale of its Deerlick Creek field in Tuscaloosa County, Alabama for $30.0 million with an effective date of July 1, 2005. The Company recorded an after tax gain on sale of oil and gas properties of $10.2 million on net proceeds of approximately $28.9 million after normal closing adjustments. The net profit earned on these assets during the six months ended December 31, 2005 was $501,000 and has been presented in discontinued operations.

On August 19, 2004, the Company completed the sale of certain interests in five fields in Louisiana and South Texas previously acquired in the Alpine acquisition, which closed on June 29, 2004, to Whiting Petroleum Corporation for $18.7 million, net of certain commissions. The Company paid $8.8 million toward its credit facility from the proceeds of the sale of these properties. There was no gain or loss on this sale transaction and the net profit earned on these assets during the quarter, since the acquisition, of $729,000 has been shown in discontinued operations net of taxes of $280,000.

On March 31, 2004, the Company completed the sale of all of its Pennsylvania properties to Castle Energy Corporation, a 25% stockholder of Delta at March 31, 2004, for cash consideration of $8 million with an effective date of January 1, 2004 and resulted in a gain on sale of oil and gas properties of $1.9 million. Revenues from the sale of these oil and gas properties were approximately $1.2 million for the year ended June 30, 2004 and $1.8 million for the year ended June 30, 2003.

On December 5, 2003, the Company completed the sale of certain properties located in Texas to Sovereign Holdings, LLC for cash consideration of $2.6 million. The effective date of the transaction was January 1, 2004 and it resulted in a loss on the sale of oil and gas properties of $28,000. Revenues attributed to the sale of these oil and gas properties were approximately $537,000 for the year ended June 30, 2004 and $1.2 million for the year ended June 30, 2003.

During the year ended June 30, 2003, the Company disposed of additional non-strategic oil and gas properties and related equipment to unaffiliated entities in addition to the dispositions described above. The Company has received proceeds from these sales of $850,000 and such sales resulted in a net gain on sale of oil and gas properties of $277,000 for the year ended June 30, 2003.

(4) DHS Drilling Company

On April 15, 2005, the Company acquired a 49.5% ownership interest in DHS Drilling Company. The investment included the contribution of all of the net assets of the then 100% owned subsidiary, Big Dog, and certain drilling assets acquired by the Company. Previously, on March 31, 2005, the Company had purchased the remaining 50% interest of Big Dog owned by Davis for 100,000 shares of the Delta's common stock valued at $1.4 million based on the closing stock price on March 31, 2005, its 50% interest in Shark and certain drilling equipment. Delta has the right to use all of the rigs on a priority basis, although approximately half are currently working for third party operators.

(5) Long Term Debt

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 semiannually on April 1 and October 1 and mature in 2015. The net proceeds were used to refinance debt outstanding under Delta's credit facility which included the amount required to acquire the Manti properties. The notes were issued at 99.50% of par and the associated discount is being amortized to interest expense over the term of the notes. The indenture governing the notes contains various restrictive covenants that may limit the Company's and its subsidiaries ability to, among other things, incur additional indebtedness, make certain investments, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and restricted subsidiaries. These covenants may limit the discretion of the Company's management in operating the Company's business. The Company was in compliance with these covenants as of December 31, 2005. The notes have been guaranteed by certain of the Company's subsidiaries (See Footnote 12, "Guarantor Financial Information"). The fair value of the Company's senior notes at December 31, 2005 was $138.4 million.

Credit Facility

On June 30, 2005, the Company amended its credit facility with Bank One, N.A., Bank of Oklahoma N.A., U.S. Bank National Association and Hibernia National Bank (the "Banks"). At December 31, 2005, the $200.0 million credit facility had an available borrowing base of approximately $75.0 million and $64.3 million outstanding. The reduction in available borrowing base was established until certain drilling results were attained. The borrowing base is redetermined semiannually and can be increased with future drilling success. The facility has variable interest rates based upon the ratio of outstanding debt to the borrowing base. Rates vary between prime + .25% and 1.00% for base rate loans and between Libor + 1.5% and 2.25% for Eurodollar loans. The rate at December 31, 2005 approximated 7%. The loan was collateralized by substantially all of the Company's oil and gas properties. Currently, the Company is required to meet certain financial covenants which include a current ratio of 1 to 1, net of derivative instruments of $12.4 million and a consolidated debt to EBITDAX (earnings before interest, taxes, depreciation, amortization and exploration) of less than 3.5 to 1. The financial covenants only include subsidiaries which the Company owns 100%. At December 31, 2005, the Company was not in compliance with its quarterly debt covenants and restrictions, but obtained a waiver from the banks for the quarter ended December 31, 2005.
In addition, the credit agreement was amended to exclude the quarter ended March 31, 2006 from the current ratio requirement.

Kaiser Francis Oil Company - Debt

On December 1, 1999, the Company borrowed $8 million at prime plus 1-1/2% from Kaiser Francis Oil Company. The proceeds from this loan were used to pay off existing debt and the balance of the Point Arguello Unit and New Mexico acquisitions. During the third quarter of fiscal 2004, the loan was paid in full.

Term Loan - DHS

On September 30, 2005, DHS completed a financing arrangement with Guggenheim Corporate Funding, LLC ("Guggenheim") for $35.0 million due September 30, 2010, with principal and interest payments due on the first calendar day of each quarter. The note bears interest at the Prime Rate plus 3.0%, or 10.25% at December 31, 2005. The note contains quarterly financial covenants applied to DHS on a stand-alone basis including a maximum leverage ratio of 2.5 to 1 (declining to 2.0 to 1.0 at June 30, 2006), a minimum current ratio of 1.25 to 1.0 and a minimum interest coverage ratio of 2.50 to 1, each as defined in the agreement. At December 31, 2005, DHS was not in compliance with its quarterly debt covenants and restrictions; however, on January 6, 2006 the note was amended with revised covenants effective as of December 31, 2005 and additional funds were borrowed (See Note 18, Subsequent Events).

(5) Long Term Debt, Continued

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

YEAR ENDING December 31,	
2006	$ 7,000
2007	7,000
2008	71,270
2009	7,000
2010	7,000
Thereafter	150,000
	$ 249,270

(6) Stockholders' Equity

Preferred Stock

The Company has 3,000,000 shares of preferred stock authorized, par value $.10 per share, issuable from time to time in one or more series. As of December 31, 2005, June 30, 2005 and June 30, 2004, no preferred stock was issued. As part of the reincorporation on January 31, 2006, the Company reduced the par value of the preferred stock to $.01 per share.

Common Stock

During the six months ended December 31, 2005 and fiscal years ended June 30, 2005, 2004 and 2003, the Company acquired oil and gas properties for 50,000, 1,571,000, 3,728,000, and 200,000 shares of the Company's common stock, respectively. The shares were valued at $799,000, $22.2 million, $30.5 million and $922,000, respectively, based on the market price of the shares at the time of issuance.

On September 27, 2005, the Company sold 5,405,418 shares of common stock to twenty-seven institutional investors at a price of $18.50 per share in cash for gross proceeds of $100.0 million and net proceeds of approximately $95.0 million. The proceeds were used to finance the Savant acquisition discussed above and to fund drilling activities.

During fiscal 2005, the Company acquired drilling equipment for 131,000 shares of the Company's common stock valued at $1.9 million.

The Company raised additional capital through the sale of 10,000,000 shares of its common stock, net of commissions, of $97.9 million for the year ended June 30, 2004. Offering costs of $6.1 million consisted of cash commissions and legal services relating to the transactions and were accounted for as an adjustment to stockholders' equity.

Non-Qualified Stock Options - Directors and Employees

On May 31, 2002 at the annual meeting of the shareholders, the shareholders ratified the Company's 2002 Incentive Plan (the "Incentive Plan") under which it reserved up to an additional 2,000,000 shares of common stock. This plan supersedes the Company's 1993 and 2001 Incentive Plans.

(6) Stockholders' Equity, Continued

Incentive awards under the Incentive 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. Options are generally issued at market price at the date of grant with various vesting and expiration terms based on the discretion of the Incentive Plan Committee.

A summary of the stock option activity under the Company's various plans and related information for the six months ended December 31, 2005 follows:

	Six Months Ended December 31, 2005			
	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding-beginning of year	3,501,401	$ 7.59		
Granted	-	-		
Exercised	(256,114)	(4.55)		
Expired / Returned	(14,000)	(14.29)		
Outstanding-end of year	3,231,287	$ 7.85	4.18	$44,980,000
Exercisable-end of year	2,614,587	$ 6.52	4.94	$39,872,000

The total intrinsic value of options exercised during the six months ended December 31, 2005 and the years ended June 30, 2005, 2004 and 2003 were $3.2 million, $24.9 million, $3.4 million, and $688,000, respectively.

A summary of Company's non-vested stock options and related information for the six months ended December 31, 2005 follows:

	Six Months Ended December 31, 2005	
	Options	Weighted-Average Grant-Date Fair Value
Nonvested-beginning of year	979,700	$ 6.99
Granted	-	-
Exercised	(349,000)	(6.18)
Forfeited / Returned	(14,000)	(6.39)
Nonvested-end of year	616,700	$ 6.97

The weighted average remaining requisite service period of the non-vested stock options was 1.35 years.

The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions for the years ended June 30, 2005, 2004 and 2003, respectively, risk-free interest rates of 4.28%, 4.32% and 2.84%, dividend yields of 0%, 0% and 0%, volatility factors of the expected market price of the Company's common stock of 43.97%, 50.43% and 65.32% and a weighted-average expected life of the options of 4.76, 5.56 and 4.16 years. The fair value of the options granted at the grant date is $8.0 million, $10.2 million and $713,000 for the years ended June 30, 2005, 2004 and 2003, respectively. No options were granted during the six months ended December 31, 2005.

(6) Stockholders' Equity, Continued

The Company has issued options to its non-employee Directors and recorded stock option expense in the amount of $329,000 and $114,000 for years ended June 30, 2004 and 2003, respectively, for options issued below market prices.

Restricted Stock - Directors and Employees

A summary of the restricted stock activity under the Company's plan and related information for the six months ended December 31, 2005 follows:

	Six Months Ended December 31, 2005			
	Restricted Stock	Weighted-Average Grant-Date Fair Value	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding-beginning of year	125,243	$ 14.71		
Granted	152,295	19.62		
Vested	(41,667)	(14.92)		
Expired / Returned	(6,638)	(14.82)		
Nonvested-end of year	229,233	$ 17.93	2.59	$4,990,000

The total fair value of restricted stock vested during the six months ended December 31, 2005 was $697,000. No restricted stock vested during any of the prior periods presented.

At December 31, 2005, the total unrecognized compensation cost related to the non-vested portion of restricted stock and stock options was $5.8 million which is expected to be recognized over a weighted average period of 4.75 years.

Cash received from exercises under all share-based payment arrangements for the six months ended December 31, 2005 and years ended June 30, 2005, 2004, and 2003 was $625,000, $132,000, $3.6 million and $975,000, respectively. Tax benefits realized from the stock options exercised during the six months ended December 31, 2005 and years ended June 30, 2005, 2004, and 2003, was zero, $1.3 million, zero and zero, respectively. During the six months ended December 31, 2005, $6.6 million of tax benefits were generated from the exercise of stock options; however, such benefit will not be recognized in stockholders' equity until the period that these amounts decrease taxes payable.

Non-Qualified Stock Options - Non-Employees

Previously, the Company had also issued options to non-employees and recorded stock option expense in the amount of $10,000 to non-employees for the year ended June 30, 2003. As of June 30, 2005, all such options had expired or been exercised.

(7) 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.

The Company adopted a 401k 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 401k 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.

For the six months ended December 31, 2005 and fiscal years ended June 30, 2005, 2004 and 2003 the Company contributed $240,000, $291,000, $262,000 and $147,000, respectively, under the plans.

(8) 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 SFAS No. 133. Accordingly, unrealized gains and losses related to the change in fair market value of derivative contracts which qualify and are designated as cash flow hedges are recorded as other comprehensive income or loss, to the extent the hedge is effective, and such amounts are reclassified to realized gain (loss) on derivative instruments as the associated production occurs.

At December 31, 2005, all of the Company's derivative contracts are collars. Under a collar agreement the Company receives the difference between the floor price and the index price only when the index price is below the floor price; and the Company pays the difference between the ceiling price and the index price only when the index price is above the ceiling price. The Company's collars are settled in cash on a monthly basis. By entering into collars, the Company effectively provides a floor for the price that it will receive for the hedged production; however, the collar also establishes a maximum price that the Company will receive for the hedged production when prices increase above the ceiling price. The Company enters into collars during periods of volatile commodity prices in order to protect against a significant decline in prices in exchange for forgoing the benefit of price increases in excess of the ceiling price on the hedged production.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the consolidated statement of operations. While such derivative contracts do not qualify for hedge accounting, management believes these contracts can be utilized as an effective component of commodity price risk management.

(8) Commodity Derivative Instruments and Hedging Activities, Continued

The following table summarizes our derivative contracts outstanding at December 31, 2005:

Commodity	Volume		Price Floor / Price Ceiling		Term	Index	Unrealized Losses at December 31, 2005 (In thousands)
Contracts that qualify for hedge accounting							
Crude oil	40,000	Bbls / month	$ 40.00 /	$ 50.34	July '05 - June '06	NYMEX-WTI	$ 3,002
Crude oil	10,000	Bbls / month	$ 45.00 /	$ 56.90	July '05 - June '06	NYMEX-WTI	416
Crude oil	25,000	Bbls / month	$ 35.00 /	$ 61.80	July '06 - June '07	NYMEX-WTI	2,445
Contracts that do not qualify for hedge accounting							
Natural gas	10,000	MMBtu / day	$ 5.00 /	$ 9.60	July '05 - June '06	NYMEX-H HUB	2,828
Natural gas	3,000	MMBtu / day	$ 6.00 /	$ 9.35	July '05 - June '06	NYMEX-H HUB	945
Natural gas	13,000	MMBtu / day	$ 5.00 /	$ 10.20	July '06 - June '07	NYMEX-H HUB	8,586
							$ 18,222

The fair value of the Company's net derivative instruments obligation was a liability of approximately $18.2 million at December 31, 2005 and $9.2 million on February 28, 2006.

The net realized losses from hedging activities recognized in the Company's statements of operations were $8.0 million, $960,000, $859,000 and $1.9 million for the six months ended December 31, 2005 and years ended June 30, 2005, 2004 and 2003, respectively. These losses are recorded as a decrease in revenues.

During the six months ended December 31, 2005, the Company's gas derivatives became ineffective under SFAS No. 133 and no longer qualified for hedge accounting. Hedge ineffectiveness results from different changes in the NYMEX contract terms and the physical location, grade and quality of the Company's oil and gas production. The change in fair value of our gas contracts during the six months ended December 31, 2005 are reflected in earnings, as opposed to previously being disclosed in other comprehensive income (loss), a component of stockholders' equity. As a result, the Company recorded a $9.9 million unrealized loss in its statement of operations as a component of other income (expense). Based on the estimated fair value of the derivative contracts at December 31, 2005, the Company expects to reclassify net losses of $6.0 million into earnings related to derivative contracts during the next twelve months; however, actual gains and losses recognized may differ materially.

(9) Income Taxes

The Company accounts for income taxes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes ("SFAS" 109). Income tax expense (benefit) attributable to income from continuing operations consisted of the following for the six months ended December 31, 2005 and fiscal years ended June 30, 2005, 2004 and 2003.

	Six Months Ended December 31, 2005	Years Ended June 30, 2005	2004	2003
		(In thousands)		
CURRENT:				
U.S. - Federal	$ -	$ -	$ -	$ -
U.S. - State	-	-	-	-
Foreign	-	-	-	-
DEFERRED:				
U.S. - Federal	(6,645)	(3,027)	-	-
U.S. - State	(994)	(298)	-	-
Foreign	-	-	-	-
	$ (7,639)	$ (3,325)	$ -	$ -

Income from continuing operations before taxes consists of the following for the six months ended December 31, 2005 and the fiscal years ended June 30, 2005, 2004 and 2003.

U.S.	(20,716)	11,276	2,297	(241)
Foreign	198	-	-	-
Income (loss) from continuing operations before taxes	$ (20,518)	$ 11,276	$ 2,297	$ (241)

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:

	Six Months Ended December 31, 2005	Years Ended June 30, 2005	2004	2003
Federal statutory rate	(35.00) %	35.00 %	35.00 %	35.00 %
State income taxes, net of federal benefit	(3.15)	3.44	3.10	2.50
Investment in DHS	(5.81)	3.53	0.25	0.25
Change in valuation allowance	0.99	(69.63)	(38.35)	(37.75)
Other	5.74	(1.83)	-	-
Actual income tax rate	(37.23) %	(29.49) %	0.00 %	0.00 %

Included in the consolidated statement of operations as a component of discontinued operations for the six months ended December 31, 2005 is a $7.4 million deferred tax provision on the sale and operations of properties that were sold during the period.

(9) Income Taxes, Continued

Deferred tax assets (liabilities) are comprised of the following at December 31, 2005, June 30, 2005 and June 30, 2004:

	Six Months Ended December 31, 2005	Years Ended June 30, 2005	Years Ended June 30, 2004
		(In thousands)	
Current deferred tax assets			
Derivative instruments	$ 4,665	$ 2,638	$ -
Accrued bonuses	452	-	-
Allowance for doubtful accounts	38	38	19
Accrued vacation liability	82	-	-
Total current deferred tax assets	5,237	2,676	19
Less valuation allowance	-	-	(19)
Net current deferred tax asset	$ 5,237	$ 2,676	$ -
Long-term deferred tax assets (liability):			
Deferred tax assets:			
Net operating loss [1]	$ 16,074	$ 14,544	$ 13,278
Asset retirement obligation	1,306	1,419	1,009
Derivative instruments	2,204	1,211	-
Percentage depletion	530	541	-
Drilling equipment	792	403	-
Equity compensation	942	-	-
Other	152	66	-
Total long-term deferred tax assets	22,000	18,184	14,287
Valuation allowance	(712)	(1,139)	(8,971)
Net deferred tax asset	21,288	17,045	5,316
Deferred tax liabilities:			
Oil and gas properties	(17,879)	(11,256)	(5,316)
Investment in DHS	(2,001)	(399)	-
Investments – available for sale	-	(503)	-
Other	(86)	-	-
Total long-term deferred tax liabilities	(19,966)	(12,158)	(5,316)
Net long-term deferred tax asset	$ 1,322	$ 4,887	$ -
Total deferred tax assets before valuation allowance	$ 27,237	$ 20,860	$ 14,306

[1]Included in net operating loss carryforwards is $1.25 million at June 30, 2005 that related to the tax effect of stock options exercised and restricted stock for which the benefit was recognized in stockholders' equity rather than in operations in accordance with FAS 109. Not included in the deferred tax asset for net operating loss at December 31, 2005 is approximately $6.6 million that relates to the tax effect of stock options exercised for which the benefit will not be recognized in stockholders' equity until the period that these amounts decrease taxes payable.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future table income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences, net of the existing valuation allowances at December 31, 2005. The valuation allowance at December 31, 2005 relates primarily to a subsidiary's net operating loss that cannot be used to reduce taxable income generated by other members of the consolidated tax group and a deferred tax asset generated by a subsidiary that is not consolidated for

(9) Income Taxes, Continued

tax purposes and does not have a history of earnings. The amount of the deferred tax asset considered realizable could be reduced if estimates of future taxable income during the carry-forward period are reduced.

At December 31, 2005, the Company had net operating loss carryforwards for regular and alternative minimum tax purposes as follows:

Regular tax net operating loss	$ 57,680
Alternative minimum tax net operating loss	54,600

If not utilized, the tax net operating loss carryforwards will expire for 2006 through 2025. At December 31, 2005, the Company had $1.1 million of net operating loss carryforward in Australia with no expiration date.

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

2006	$ 346
2007	1,827
2008	720
2009	3,914
2010	6,004
2011 and thereafter	44,869
	$ 57,680

(10) Related Party Transactions

Transactions with Officers

On September 29, 2005 we acquired an undivided 50% working interest in approximately 145,000 net undeveloped acres in the Columbia River Basin in Washington and purchased an interest in undeveloped acreage in the Piceance Basin in Colorado from Savant Resources, LLC ("Savant") for an aggregate purchase price of $85.0 million in cash. James Wallace, one of our directors, owns approximately a 1.7% interest in Savant, and also serves as a director of Savant. The majority of the acquired acreage in the Columbia River Basin consolidates our current leasehold position.

During the quarter ended September 30, 2005, DHS borrowed $8.0 million from Chesapeake, a related party who owns approximately a 45% interest in DHS. The loan was subsequently paid in full upon completion of the Guggenheim financing discussed in Footnote 5, Long Term Debt.

Until March 12, 2003, the Company's Board of Directors had granted each of our officers the right to participate in the drilling, on the same terms as the Company, in up to a five percent (5%) working interest in any well drilled, re-entered, completed or re-completed by the Company on its acreage (provided that any well to be re-entered or re-completed was then producing economic quantities of hydrocarbons). On March 12, 2003, the Board of Directors rescinded this right. The officers did not participate in any Company wells since fiscal 2003.

During fiscal 2001 and 2000, Mr. Larson and Mr. Parker guaranteed certain borrowings which have subsequently been paid in full. 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 $58,000, $100,000, $66,000 and $108,000 for their respective 1% ORRI during the six months ended December 31, 2005 and fiscal 2005, 2004 and 2003, respectively.

The Company's officers have employment agreements which, among other things, include termination and change of control clauses.

(10) Related Party Transactions, Continued

Accounts Receivable Related Parties

At December 31, 2005, the Company had $54,000 of receivables from related parties. These amounts include drilling costs and lease operating expense on wells owned by the related parties and operated by the Company.

(11) Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share:

	Six Months Ended December 31, 2005	Years Ended June 30, 2005	2004	2003
		(In thousands, except per share amounts)		
Numerator:				
Numerator for basic and diluted earnings per share - income (loss) available to common stockholders	$ (590)	$ 15,050	$ 5,056	$ 1,257
Denominator:				
Denominator for basic earnings per share-weighted average shares outstanding	44,959	40,327	27,041	22,865
Effect of dilutive securities, stock options	- [1]	1,693	2,591	954
Denominator for diluted earnings per common share	44,959	42,020	29,632	23,819
Basic earnings per common share	$ (.01)	$ .37	$ .19	$ .05
Diluted earnings per common share	$ (.01)	$ .36	$ .17	$ .05

[1]The denominator for diluted earnings per common share for the six months ended December 31, 2005 excludes 1,944,000 potentially dilutive shares because such shares were anti-dilutive.

(12) Guarantor Financial Information

Delta ("Issuer") issued 7% Senior Notes ("Bond Offering") on March 15, 2005, for the aggregate amount of $150.0 million, which pay interest semiannually on April 1st and October 1st and mature in 2015. The proceeds were used to refinance debt outstanding under the Company's credit facility. This Bond Offering is guaranteed by all of the 100% owned subsidiaries of the Company at the time of the Bond Offering ("Guarantors"). The Guarantors, fully, jointly and severally, irrevocably and unconditionally guarantee the performance and payment when due of all the obligations under the Bond Offering. Big Dog, Shark, DHS and Amber ("Non-guarantors") are not guarantors of the indebtedness under the Bond Offering.

The following financial information sets forth the Company's condensed consolidating balance sheets as of December 31, 2005 and June 30, 2005 and 2004, the condensed consolidating statements of operations for the six months ended December 31, 2005 and the years ended June 30, 2005, 2004 and 2003 and the condensed consolidating statements of cash flows for the six months ended December 31, 2005 and years ended June 30, 2005, 2004 and 2003 (in thousands).

(12) Guarantor Financial Information, Continued

Condensed Consolidated Balance Sheet
December 31, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 50,519	$ 1,050	$ 10,020	$ -	$ 61,589
Property and equipment:					
Oil and gas	550,916	49,886	5,007		605,809
Drilling rigs and trucks	-	-	64,129	-	64,129
Other	12,266	-	543	-	12,809
Total property and equipment	563,182	49,886	69,679	-	682,747
Accumulated DD&A	(56,733)	(1,188)	(3,672)	-	(61,593)
Net property and equipment	506,449	48,698	66,007	-	621,154
Investment in subsidiaries	(4,295)	-	-	4,295	-
Other long-term assets	8,028	-	2,622	-	10,650
Total assets	$ 560,701	$ 49,748	$ 78,649	$ 4,295	$ 693,393
Current liabilities	$ 92,426	$ 352	$ 13,994	$ -	$ 106,772
Long-term liabilities					
Long-term debt	218,304	-	29,364	-	247,668
Asset retirement obligation	2,975	27	-	-	3,002
Total long-term liabilities	221,279	27	29,364	-	250,670
Minority interest	15,496	-	-	-	15,496
Stockholders' equity	231,500	49,369	35,291	4,295	320,455
Total liabilities and stockholders' equity	$ 560,701	$ 49,748	$ 78,649	$ 4,295	$ 693,393

(12) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Operations
Six Months Ended December 31, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 51,062	$ 1,616	$ 16,316	$ (7,220)	$ 61,774
Operating expenses:					
Lease operating expense	13,626	178	-	-	13,804
Depreciation and depletion	17,420	158	2,846	-	20,424
Exploration expense	3,408	(1)	4	-	3,411
Drilling and trucking operations	-	-	9,545	(3,724)	5,821
Dry hole, abandonment and impaired	4,073	-	-	-	4,073
General and administrative	15,263	7	1,221	-	16,491
Total expenses	53,790	342	13,616	(3,724)	64,024
Income (loss) from continuing operations	(2,728)	1,274	2,700	(3,496)	(2,250)
Other income and expenses	(16,581)	4	(1,003)	(688)	(18,268)
Income tax benefit	7,639	-	-	-	7,639
Discontinued operations	12,289	-	-	-	12,289
Net income (loss)	$ 619	$ 1,278	$ 1,697	$ (4,184)	$ (590)

Condensed Consolidated Statement of Cash Flows
Six Months Ended December 31, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 21,477	$ (1,244)	$ 4,646	$ 24,879
Investing activities	(96,840)	1,472	(51,140)	(146,508)
Financing activities	75,314	(209)	49,802	124,907
Net increase (decrease) in cash and cash equivalents	(49)	19	3,308	3,278
Cash at beginning of the period	1,999	196	46	2,241
Cash at the end of the period	$ 1,950	$ 215	$ 3,354	$ 5,519

(12) Guarantor Financial Information, Continued

Condensed Consolidated Balance Sheet
June 30, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 23,602	$ 2,235	$ 1,197	$ -	$ 27,034
Property and equipment:					
Oil and gas	455,678	6,556	5,007		467,241
Drilling rigs and trucks	-	-	40,031	-	40,031
Other	10,347	-	65	-	10,412
Total property and equipment	466,025	6,556	45,103	-	517,684
Accumulated DD&A	(42,003)	(1,032)	(1,099)	-	(44,134)
Net property and equipment	424,022	5,524	44,004	-	473,550
Investment in subsidiaries	26,322	-	-	(26,322)	-
Other long-term assets	12,359	-	40	-	12,399
Total assets	$ 486,305	$ 7,759	$ 45,241	$ (26,322)	$ 512,983
Current liabilities	$ 42,294	$ 215	$ 11,641	$ -	$ 54,150
Long-term liabilities					
Long-term debt	219,437	-	184	-	219,621
Asset retirement obligation	2,951	24	-	-	2,975
Total long-term liabilities	222,388	24	184	-	222,596
Minority interest	14,614	-	-	-	14,614
Stockholders' equity	207,009	7,520	33,416	(26,322)	221,623
Total liabilities and stockholders' equity	$ 486,305	$ 7,759	$ 45,241	$ (26,322)	$ 512,983

(12) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Operations
Year Ended June 30, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 88,254	$ 1,657	$ 7,319	$ (2,523)	$ 94,707
Operating expenses:					
Lease operating expense	21,780	489	-	-	22,269
Depreciation and depletion	21,534	148	1,525	-	23,207
Exploration expense	6,155	-	-	-	6,155
Drilling and trucking operations	-	-	6,799	(2,133)	4,666
Dry hole, abandonment and impaired	2,771	-	-	-	2,771
General and administrative	15,788	9	1,133	-	16,930
Total expenses	68,028	646	9,457	(2,133)	75,998
Income (loss) from continuing operations	20,226	1,011	(2,138)	(390)	18,709
Other income and expenses	(7,462)	31	(2)	-	(7,433)
Income tax benefit	3,325	-	-	-	3,325
Discontinued operations	449	-	-	-	449
Net income (loss)	$ 16,538	$ 1,042	$ (2,140)	$ (390)	$ 15,050

Condensed Consolidated Statement of Cash Flows
Year Ended June 30, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 37,057	$ 707	$ 7,098	$ 44,862
Investing activities	(158,273)	(551)	(25,058)	(183,882)
Financing activities	121,262	-	17,921	139,183
Net increase (decrease) in cash and cash equivalents	46	156	(39)	163
Cash at beginning of the period	1,992	40	46	2,078
Cash at the end of the period	$ 2,038	$ 196	$ 7	$ 2,241

(12) Guarantor Financial Information, Continued

Condensed Consolidated Balance Sheet
Year Ended June 30, 2004

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 13,781	$ 1,115	$ 57	$ -	$ 14,953
Property and equipment:					
Oil and gas	261,879	6,007	5,006	-	272,892
Drilling rigs and trucks	-	-	3,965	-	3,965
Other	1,136	-	11	-	1,147
Total property and equipment	263,015	6,007	8,982	-	278,004
Accumulated DD&A	(20,765)	(886)	(14)	-	(21,665)
Net property and equipment	242,250	5,121	8,968	-	256,339
Investment in subsidiaries	14,724	-	-	(14,724)	-
Other long-term assets	1,412	-	-	-	1,412
Total assets	$ 272,167	$ 6,236	$ 9,025	$ (14,724)	$ 272,704
Current liabilities	$ 14,018	$ 36	$ 236	$ -	$ 14,290
Long-term liabilities					
Long-term debt	69,387	-	243	-	69,630
Asset retirement obligation	2,520	22	-	-	2,542
Total long-term liabilities	71,907	22	243	-	72,172
Minority interest	245	-	-	-	245
Stockholders' equity	185,997	6,178	8,546	(14,724)	185,997
Total liabilities and stockholders' equity	$ 272,167	$ 6,236	$ 9,025	$ (14,724)	$ 272,704

Condensed Consolidated Statement of Operations
Year Ended June 30, 2004

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 34,947	$ 1,429	$ 33	$ (33)	$ 36,376
Operating expenses:					
Lease operating expense	9,377	399	-	-	9,776
Depreciation and depletion	9,637	263	14	-	9,914
Exploration expense	2,405	-	1	-	2,406
Drilling and trucking operations	-	-	265	(33)	232
Dry hole, abandonment and impaired	2,132	-	-	-	2,132
General and administrative	7,906	19	124	-	8,049
Total expenses	31,457	681	404	(33)	32,509
Income (loss) from continuing operations	3,490	748	(371)	-	3,867
Other income and expenses	(1,643)	4	(1)	70	(1,570)
Discontinued operations	2,759	-	-	-	2,759
Net income (loss)	$ 4,606	$ 752	$ (372)	$ 70	$ 5,056

(12) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Cash Flows
Year Ended June 30, 2004

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 9,263	$ 518	$ (158)	$ 9,623
Investing activities	(144,232)	(370)	(3,836)	(148,438)
Financing activities	134,795	(218)	4,045	138,622
Net increase (decrease) in cash and cash equivalents	(174)	(70)	51	(193)
Cash at beginning of the period	2,160	110	1	2,271
Cash at the end of the period	$ 1,986	$ 40	$ 52	$ 2,078

Condensed Consolidated Statement of Operations
Year Ended June 30, 2003

	Guarantor Issuer	Non-Guarantor Subsidiaries	Subsidiaries	Consolidated
Total revenue	$ 19,119	$ 1,599	$ -	$ 20,718
Operating expenses:				
Lease operating expense	7,957	453	-	8,410
Depreciation and depletion	4,475	524		4,999
Exploration expense	140	-	-	140
Drilling and trucking operations	-	-	-	-
Dry hole, abandonment and impaired	530	7	-	537
General and administrative	4,987	21	129	5,137
Total expenses	18,089	1,005	129	19,223
Income (loss) from continuing operations	1,030	594	(129)	1,495
Other income and expenses	(1,770)	14	-	(1,756)
Discontinued operations	1,322	196	-	1,518
Net income (loss)	$ 582	$ 804	$ (129)	$ 1,257

(12) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Cash Flows
Year Ended June 30, 2003

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 7,042	$ 1,083	$ (126)	$ 7,999
Investing activities	(14,837)	82	107	(14,648)
Financing activities	8,992	(1,101)	5	7,896
Net increase (decrease) in cash and cash equivalents	1,197	64	(14)	1,247
Cash at beginning of the period	978	46	-	1,024
Cash at the end of the period	$ 2,175	$ 110	$ (14)	$ 2,271

(13) Commitments

The Company leases office space in Denver, Colorado and certain other locations in North America and also leases equipment and autos under non-cancelable operating leases. Rent expense, for the six months ended December 31, 2005 and years ended June 30, 2005, 2004 and 2003 was approximately $432,000, $491,000, $311,000 and $210,000, respectively. The following table summarizes the future minimum payments under all non-cancelable operating lease obligations:

	(In thousands)
2006	$ 1,843
2007	1,869
2008	1,822
2009	1,721
2010	1,199
2011 and thereafter	4,100
	$ 12,554

The Company has entered into agreements with four executive officers which provide for severance payments, two times the calculated average of the officer's combined annual salary and bonus, benefit continuation and accelerated vesting of options and stock grants in the event there is a change in control of the Company. The agreements expire no later than December 31, 2006, subject to automatic annual one-year renewals until cancelled by the Company.

(14) 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 six months ended December 31, 2005 and year ended June 30, 2005. Prior to the fiscal year ended June 30, 2005, the Company only operated in the Oil and Gas segment.

	Oil and Gas	Drilling	Inter-segment Eliminations	Consolidated
		(In thousands)		
Six Months Ended December 31, 2005				
Revenues from external customers	$ 52,678	$ 9,096	$ -	$ 61,774
Inter-segment revenues	-	7,220	(7,220)	-
Total revenues	$ 52,678	$ 16,316	$ (7,220)	$ 61,774
Operating income (loss)	$ (1,511)	$ 2,757	$ (3,496)	$ (2,250)
Other income and (expense) [1]	(16,577)	(1,003)	(688)	(18,268)
Income (loss) from continuing operations, before tax	$(18,088)	$ 1,754	$ (4,184)	$(20,518)
Year Ended June 30, 2005				
Revenues from external customers	$ 89,911	$ 4,796	$ -	$ 94,707
Inter-segment revenues	-	2,523	(2,523)	-
Total revenues	$ 89,911	$ 7,319	$ (2,523)	$ 94,707
Operating income (loss)	$ 21,125	$ (2,028)	$ (388)	$ 18,709
Other income and (expense) [1]	(8,448)	(2)	1,017	(7,433)
Income (loss) from continuing operations, before tax	$ 12,677	$ (2,030)	$ 629	$ 11,276

[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. Minority interest is included in inter-segment eliminations.

(15) Selected Quarterly Financial Data (Unaudited)

	Quarter Ended			
	September 30,	December 31,	March 31,	June 30,
	(In thousands, except per share amounts)			
Six Months Ended December 31, 2005				
Total revenue	$ 31,978	$ 29,796	N/A	N/A
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	(20,166)	(352)		
Net income (loss)	(2,163)	1,573		
Net income (loss) per common share: (1)				
Basic	$ (.05)	$ .03		
Diluted	$ (.05)	$ .03		
Year Ended June 30, 2005				
Total revenue	$ 19,338	$ 20,529	$ 26,566	$ 28,274
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	3,215	4,809	4,940	(1,688)
Net income	3,944	4,809	4,940	1,357
Net income per common share: (1)				
Basic	$ .10	$ .12	$ .12	$ .04
Diluted	$ .09	$ .11	$ .12	$ .04
Year Ended June 30, 2004				
Total revenue	$ 6,755	$ 7,646	$ 10,308	$ 11,658
Income from continuing operations before income taxes, discontinued operations and cumulative effect	1,045	425	374	453
Net income	1,364	652	2,454	586
Net income per common share: (1)				
Basic	$ .06	$ .03	$ .09	$ .02
Diluted	$ .05	$ .03	$ .08	$ .02

(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.

(16) Disclosures About Capitalized Costs, Costs Incurred and Major Customers

Capitalized costs related to oil and gas activities are as follows:

	December 31,	June 30,	
	2005	2005 (In thousands)	2004
Unproved offshore California properties	$ 10,960	$ 10,925	$ 10,844
Unproved onshore domestic properties	156,183	91,010	38,903
Proved offshore California properties	13,678	12,207	9,103
Proved onshore domestic properties	424,988	353,099	214,042
	605,809	467,241	272,892
Accumulated depreciation and depletion	(57,922)	(43,034)	(21,317)
	$ 547,887	$ 424,207	$ 251,575

Costs incurred[1] in oil and gas activities are as follows:

	Six Months Ended December 31,		Years Ended June 30,					
	2005		2005		2004 (In thousands)		2003	
	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Unproved property acquisition costs	$ 88,116	$ 35	$ 25,383	$ 81	$ 37,223	$ 680	$ 694	$ 442
Proved property acquisition costs	4,386	82	81,190	-	128,587	-	10,784	-
Developed costs incurred on undeveloped reserves	30,891	1,389	72,413	3,104	3,789	1,070	815	986
Development costs – other	54,591	-	36,369	-	20,986	-	4,335	-
Exploration costs	3,411	-	6,155	-	2,406	-	140	-
	$ 181,395	$ 1,506	$ 221,510	$ 3,185	$ 192,991	$ 1,750	$ 16,768	$ 1,428

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

(16) Disclosures About Capitalized Costs, Cost Incurred and Major Customers, Continued

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

	Six Months Ended December 31, 2005		Years Ended June 30, (In thousands)					
	2005		2005		2004		2003	
	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Revenue								
Oil and gas revenues	$ 56,846	$ 3,810	$ 85,680	$ 5,191	$ 33,251	$ 3,975	$ 17,987	$ 4,589
Expenses:								
Production costs	11,677	2,128	18,344	3,925	6,510	3,257	5,140	3,270
Depletion	16,759	382	20,171	720	8,978	705	3,860	1,075
Exploration	3,411	-	6,155	-	2,406	-	140	-
Abandonment and impaired properties	-	-	-	-	-	-	-	-
Dry hole costs	4,073	-	2,771	-	2,132	-	537	-
Results of operations of oil and gas producing activities	$ 20,926	$ 1,300	$ 38,239	$ 546	$ 13,225	$ 13	$ 8,310	$ 244
Income (loss) from operations of properties sold, net	501	-	449	-	872	-	1,241	-
Gain (loss) on sale of properties	11,788	-	-	-	1,887	-	277	-
Cumulative effect on change in accounting and principle	-	-	-	-	-	-	(20)	-
Results of discontinued operations of oil and gas producing activities	$ 12,289	$ -	$ 449	$ -	$ 2,759	$ -	$ 1,498	$ -

The Company's sales of oil and gas to individual customers which exceeded 10% of the Company's total oil and gas sales for the six months ended December 31, 2005 and the years ended June 30, 2005, 2004 and 2003 were:

	Six Months Ended December 31,	Years Ended June 30,		
	2005	2005	2004	2003
Customer A	15%	6%	-%	-%
Customer B	14%	3%	-%	-%
Customer C	12%	9%	5%	-%
Customer D	8%	10%	17%	13%
Customer E	5%	6%	10%	18%
Customer F	4%	7%	17%	-%
Customer G	1%	3%	14%	17%

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

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 and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. For the purposes of this disclosure, the Company has included reserves it is committed to and anticipates drilling.

(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.

Estimates of our oil and natural gas reserves and present values as of December 31, 2005, and June 30, 2005, 2004 and 2003 are derived from reserve reports prepared by Ralph E. Davis Associates, Inc., our independent reserve engineers with respect to onshore reserves, or Mannon Associates, our independent reserve engineers with respect to offshore reserves.

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

A summary of changes in estimated quantities of proved reserves for the six months ended December 31, 2005 and the years ended June 30, 2005, 2004 and 2003 is as follows:

	Onshore		Offshore
	GAS (MMcf)	OIL (MBbl)	OIL (MBbl)
		(In thousands)	
Estimated Proved Reserves: Balance at July 1, 2002	43,953	3,919	902
Revisions of quantity estimate	13,719	(927)	244
Extensions and discoveries	687	-	1,132
Purchase of properties	236	1,024	-
Sale of properties	(457)	(66)	-
Production	(2,938)	(252)	(227)
Estimated Proved Reserves: Balance at June 30, 2003	55,200	3,698	2,051
Revisions of quantity estimate	(3,136)	469	(44)
Extensions and discoveries	6,560	69	-
Purchase of properties	39,782	8,306	-
Sale of properties	(6,817)	(596)	-
Production	(3,110)	(568)	(180)
Estimated Proved Reserves: Balance at June 30, 2004	88,479	11,378	1,827
Revisions of quantity estimate	(3,850)	(512)	(173)
Extensions and discoveries	39,459	1,162	-
Purchase of properties	32,282	1,397	-
Sale of properties	(7,654)	(153)	-
Production	(7,675)	(899)	(156)
Estimated Proved Reserves: Balance at June 30, 2005	141,041	12,373	1,498
Revisions of quantity estimate	(4,683)	(506)	(468)
Extensions and discoveries	58,725	2,542	-
Purchase of properties	11,816	-	-
Sale of properties	(22,025)	(221)	-
Production	(3,720)	(428)	(81)
Estimated Proved Reserves: Balance at December 31, 2005	181,154	13,760	949
Proved developed reserves:			
June 30, 2002	25,100	1,651	849
June 30, 2003	28,611	2,608	919
June 30, 2004	55,786	6,240	695
June 30, 2005	70,568	6,947	585
December 31, 2005	56,852	7,171	657

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

Future net cash flows presented below are computed using year end prices and costs and are net of all overriding royalty revenue interests.

Future corporate overhead expenses and interest expense have not been included.

	Onshore	Offshore (In thousands)	Combined
December 31, 2005			
Future net cash flows	$ 2,613,958	$ 45,420	$ 2,659,378
Future costs:			
Production	481,537	21,970	503,507
Development and abandonment	318,704	2,950	321,654
Income taxes	471,125	5,325	476,450
Future net cash flows	1,342,592	15,175	1,357,767
10% discount factor	(604,355)	(3,788)	(608,143)
Standardized measure of discounted future net cash flows	$ 738,237	$ 11,387	$ 749,624
Estimated future development cost anticipated for fiscal 2006 and 2007 on existing properties	$ 202,524	$ 1,729	$ 204,253
June 30, 2005			
Future net cash flows	$ 1,724,986	$ 64,516	$ 1,789,502
Future costs:			
Production	366,453	19,286	385,739
Development and abandonment	183,416	8,934	192,350
Income taxes	294,754	-	294,754
Future net cash flows	880,363	36,296	916,659
10% discount factor	(387,874)	(11,415)	(399,289)
Standardized measure of discounted future net cash flows	$ 492,489	$ 24,881	$ 517,370
June 30, 2004			
Future net cash flows	$ 953,532	$ 51,625	$ 1,005,157
Future costs:			
Production	225,046	23,558	248,604
Development and abandonment	55,845	11,054	66,899
Income taxes	165,492	-	165,492
Future net cash flows	507,149	17,013	524,162
10% discount factor	(230,540)	(5,585)	(236,125)
Standardized measure of discounted future net cash flows	$ 276,609	$ 11,428	$ 288,037

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

	Onshore	Offshore (In thousands)	Combined
June 30, 2003			
Future cash flows	$ 377,458	$ 46,898	$ 424,356
Future costs:			
Production	99,243	24,787	124,030
Development and abandonment	20,104	13,137	33,241
Income taxes	62,390	-	62,390
Future net cash flows	195,721	8,974	204,695
10% discount factor	(93,734)	(3,750)	(97,484)
Standardized measure of discounted future net cash flows	$ 101,987	$ 5,224	$ 107,211

The principal sources of changes in the standardized measure of discounted net cash flows during the six months ended December 31, 2005 and the fiscal years ended June 30, 2005, 2004 and 2003 are as follows:

	Six Months Ended December 31,	Years Ended June 30,		
	2005	2005	2004 (In thousands)	2003
Beginning of the year	$ 517,370	$ 288,037	$ 107,211	$ 62,384
Sales of oil and gas production during the period, net of production costs	(47,746)	(68,602)	(27,459)	(16,082)
Purchase of reserves in place	58,790	201,693	248,478	14,335
Net change in prices and production costs	170,831	90,938	26,088	37,957
Changes in estimated future development costs	(50,676)	19,345	8,592	(8,251)
Extensions, discoveries and improved recovery	336,920	93,624	11,599	3,032
Revisions of previous quantity estimates, estimated timing of development and other	(164,632)	(91,002)	(25,807)	25,675
Previously estimated development and abandonment costs incurred during the period	32,280	72,413	4,859	1,801
Sales of reserves in place	(56,276)	(42,508)	(17,934)	(1,122)
Change in future income tax	(98,974)	(75,371)	(58,311)	(18,756)
Accretion of discount	51,737	28,803	10,721	6,238
End of year	$ 749,624	$ 517,370	$ 288,037	$ 107,211

(18) Subsequent Events

Castle Acquisition
As announced on November 8, 2005, Delta has entered into a merger agreement with Castle Energy Corporation ("Castle") that has been approved by both Boards of Directors. Delta will acquire Castle, which holds 6,700,000 shares of Delta, and would issue 8,500,000 shares of its common stock to Castle's stockholders, for a net issuance of 1,800,000 shares of common stock. Castle also has additional assets of approximately $22.4 million which is comprised of cash, producing oil and gas properties located in Pennsylvania and West Virginia, and certain other assets. The merger is subject to the approval of the Castle stockholders and is expected to close during the first half of 2006. On February 17, 2006, Delta and Castle amended the merger agreement to extend the merger completion date from April 1, 2006 to May 1, 2006.

DHS Term Loan Amendment
On January 6, 2006, DHS amended its Guggenheim note to provide for an additional $10.0 million in borrowings and amend certain of the financial covenants as follows. The covenant for Maximum Consolidated Leverage Ratio of 2.5 to 1 (declining to 2.0 to 1.0 at June 30, 2006) was amended to a ratio of 3.0 to 1, 2.75 to 1, and 2.50 to 1 for the quarters ending December 31, 2005, March 31, 2006, and June 30, 2006 respectively. For subsequent quarters, the ratio is 2.00 to 1, as per the original covenants. Additionally, the current ratio covenant was modified, eliminating the current portion of long term debt from the current liabilities component of the ratio. The Minimum Consolidated Interest Coverage Ratio was not amended. The amended note remains due on September 30, 2010, with quarterly principal payments of $2.25 million beginning April 1, 2006, and one balloon payment on September 30, 2010 of $2.75 million. The interest rate on the note was modified to Prime plus 3.5% until such time as, one, the Maximum Consolidated Leverage Ratios complies with the original ratios, and, two, the ratio of the long term debt to the appraised value of the Company's equipment is equal to or less than 55%. When the additional $10 million was secured, the ratio was 57% ($45 million outstanding on loan/$78.95 million appraised value). After the first quarterly payment in January 2006, the ratio dropped to 55% ($43.25 million outstanding on loan/$78.95 million appraised value). When the ratios on the original covenant are achieved and the appraised value ratio is 55% or lower, the interest rate will change to the original rate (Prime plus 3.0%). Financing costs of $100,000 were incurred in conjunction with the amendment, and will be amortized over the remaining life of the note.

CRB Sale
During December 2005, Delta transferred its ownership in approximately 427,000 gross acres (64,000 net acres) of non-operated interests in the Columbia River Basin to a newly created wholly owned subsidiary, CRB Partners, LLC. In January 2006, Delta sold a minority in CRB Partners, LLC. The Company expects to record a gain of during the first quarter of 2006 as a result of the transaction. The Company plans to use the proceeds from such sale to initially reduce borrowings under its senior secured debt facility and to later accelerate its rate of development drilling. As a result of the transaction, Delta now owns a net interest of just over 40,000 acres in the Columbia River Basin through its remaining ownership of CRB Partners, LLC and additional interests in 332,000 net acres in the Columbia River Basin from previous transactions.

DHS Rig Acquisitions
On January 26, 2006, Delta Petroleum purchased Rooster Drilling Company for 350,000 shares of Delta common stock valued at $8.2 million. Delta plans to contribute Rooster Drilling to DHS Drilling Company. Rooster Drilling owns one drilling rig, which will become DHS Drilling Company Rig 15. The rig is an Oilwell 66, with a depth capacity of 12,000 feet. The rig is located in Wyoming and is under contract to drill 9 wells (or minimum 100 days), in the Big Piney area of Wyoming.

(18) Subsequent Events, Continued

In February 2006, DHS committed to purchase a Kremco 750G drilling rig for $4.75 million. The rig is a 500 horsepower rig, with a depth rating of 10,000 feet. The rig, currently located in Canada, will be purchased from a dealer in Casper, Wyoming, with delivery expected in March 2006. DHS will take delivery of the rig in Casper, Wyoming, and after upgrades in the DHS yard in Casper, the rig is scheduled to commence work in the Rocky Mountain region in the second quarter, 2006.

Central Utah Acquisition

On February 1, 2006 Delta entered into a purchase and sale agreement with Armstrong Resources, LLC ("Armstrong") to acquire a 65% working interest in approximately 88,000 acres in the central Utah hingeline play for a purchase price of $24 million in cash and 673,000 shares of common stock. The agreement is effective for all purposes as of January 26, 2006. Armstrong will retain the remaining 35% working interest in the acreage. As part of the transaction, Delta will pay 100% of the drilling costs for the first three wells in the project. Delta will be the operator of the majority of the acreage, and drilling is expected to begin during 2006. In conjunction with the Central Utah Acquisition, Delta filed a registration statement with the Securities and Exchange Commission and sold 1.5 million shares of common stock. The net proceeds of $33.9 million from the offering were used to fund the cash portion of the acquisition purchase price and for general corporate purposes.

GLOSSARY OF OIL AND GAS TERMS

The terms defined in this section are used throughout this Report.

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.

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.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

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.

REPORT ON FORM 10-K

A Copy of Delta's Transition Report on Form 10-K for the six months ended December 31, 2005, will be provided to holders of the Company's securities at no charge on request by contacting the Company at 303-293-9133, or writing to the attention of the Corporate Secretary at 370 17th Street, Suite 4300, Denver, Colorado 80202.

OFFICERS AND DIRECTORS

Roger A. Parker
CEO and Chairman

John R. Wallace
President and COO

Kevin K. Nanke
Treasurer, CFO

Kevin R. Collins
Director

Jerrie F. Eckelberger
Director

Aleron H. Larson, Jr.
Director

Russell S. Lewis
Director

Jordan R. Smith
Director

Neal A. Stanley
Director

James P. Van Blarcom
Director

James B. Wallace
Director

CORPORATE INFORMATION

Stock Listing
NASDAQ
Symbol–DPTR

Independent Auditors
KPMG LLP
Denver, Colorado

Transfer Agent
Corporate Stock Transfer, Inc.
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

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

The annual meeting of Stockholders of Delta Petroleum Corporation will be held at 8:30 a.m. MDT on October 17, 2006 at the Brown Palace Hotel, 321 17th Street, Denver CO 80202.

DELTA