

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K
ANNUAL REPORT

PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED JUNE 30, 2011
COMMISSION FILE NUMBER 001-34144

CUBIC ENERGY, INC.

(Exact Name of Registrant as Specified in its Charter)

TEXAS **87-0352095**
(State of Incorporation) (I.R.S. Employer Identification No.)
9870 PLANO ROAD, DALLAS, TEXAS 75238
(Address of Principal Executive Offices)
972-686-0369
(Registrant's Telephone Number)

Securities registered pursuant to Section 12(b) of the Act:

<u>Title of Class</u>	<u>Name of Exchange on Which Registered</u>
Common Stock, \$0.05 par value	NYSE Amex, LLC

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

Indicate by check mark if registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes [] No [X]

Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes [] No [X]

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

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

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

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

Large accelerated filer []

Non-accelerated filer []

Accelerated filer []

Smaller reporting company [X]

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

State the aggregate market value of the common stock, par value \$0.05 per share, held by non-affiliates computed by reference to the price at which the common stock was last sold, or the average bid and asked prices of such common stock, as of the last business day of the registrant's most recently completed second fiscal quarter: As of December 31, 2010 the aggregate market value held by non-affiliates was \$31,958,504.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: As of September 9, 2011, there were 76,815,908 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None.

Special note regarding forward-looking statements

This annual report on Form 10-K contains forward-looking statements, as defined in Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, are forward-looking statements. These forward-looking statements relate to, among other things, the following: our future financial and operating performance and results; our business strategy; market prices; and our plans and forecasts.

Forward-looking statements are identified by use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achievable,” “anticipate,” “will,” “continue,” “potential,” “should,” “could” and similar words and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements. You should consider carefully the statements in the “Risk Factors” section of this report and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements, including, but not limited to, the following factors:

- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to service our debt and fully develop our undeveloped acreage positions;
- the outcome of our dispute with the counterparties of certain drilling credits owed to us;
- the volatility in commodity prices for oil and natural gas;
- the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes);
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the ability to replace oil and natural gas reserves;
- lease or title issues or defects to our oil and gas properties;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;
- competition, including competition for acreage in oil and natural gas producing areas;
- management’s ability to execute our plans to meet our goals;
- our ability to retain key members of senior management;
- our ability to obtain goods and services, such as drilling rigs and other oilfield equipment, and access to adequate gathering systems and pipeline take-away capacity, to execute our drilling program;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including that the United States economic slow-down might continue to negatively affect the demand for natural gas, oil and natural gas liquids;
- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and
- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or pricing.

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

CUBIC ENERGY, INC.

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PART I

Item 1. Business.

GENERAL

Cubic Energy, Inc. (referred to as "Cubic", "we", "our", "us" or the "Company") is an independent energy company engaged in the development and production of, and exploration for, crude oil, natural gas and natural gas liquids. Our oil and gas assets are concentrated in Texas and Louisiana. At June 30, 2011, our total proved reserves were 57,699,279 Mcfe.

The Company's future results of operations and growth are substantially dependent upon (i) its ability to acquire or find new oil and gas properties, or successfully develop existing oil and gas properties and (ii) the prevailing prices for oil and gas. Numerous locations have been identified by third-party operators for additional drilling. If we are unable to economically complete additional producing wells, the Company's oil and gas production, and its revenues, would likely decline rapidly as its reserves are depleted. In addition, oil and gas prices are dependent upon numerous factors beyond the Company's control, such as economic, political, governmental, environmental and regulatory developments, as well as competition from other sources of energy. The oil and gas markets have historically been very volatile, and any further significant or extended decline in the price of gas would have a material adverse effect on the Company's financial condition and results of operations, and could result in a further reduction in the carrying value of the Company's proved reserves and adversely affect its access to capital.

Louisiana Acreage

Our corporate strategy with respect to our asset acquisition and development efforts was to position the Company in low risk opportunities while building mainstream high yield reserves. The acquisition of our acreage in DeSoto and Caddo Parishes, Louisiana, puts us in reservoir rich environments in the Hosston, Cotton Valley and Bossier/Haynesville Shale formations, with additional shallow formations to exploit as well. We have had success on our acreage with wells completed in the Hosston, Cotton Valley and Bossier/Haynesville Shale formations. We also own an interest in the right-of-ways, infrastructure and pipelines for our Caddo and DeSoto Parish, Louisiana acreage.

We share our Bossier/Haynesville formation acreage with Goodrich Petroleum Corporation ("Goodrich"), Chesapeake Energy Corporation ("Chesapeake"), Petrohawk Energy Corporation ("Petrohawk"), El Paso E&P Company, L.P. ("El Paso"), BG US Production Company, LLC ("BG"), EXCO Operating Company, LP ("EXCO") and Indigo Minerals, LLC ("Indigo Minerals"), and all of these companies are third-party operators actively working on our shared acreage. As a result of this activity, we saw improved production volumes in each of the last three fiscal years.

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

Management believes in the value of our assets, which are being drilled by third-party operators, and will continue to explore strategic alternatives that allow us to leverage those assets to gain full stockholder value.

Texas Acreage

Our Texas properties are situated in Eastland and Callahan Counties. The Texas properties consist primarily of wells acquired in several transactions between 1991 and 2002 and through overriding royalty interests reserved in farm-out agreements in 1998 and 1999. These wells produce limited amounts of natural gas and oil condensate.

HISTORY

Our predecessor was incorporated in October 1978. Cubic was incorporated in 1999 in the State of Texas. Our principal executive office is located at 9870 Plano Road, Dallas, Texas 75238, and our telephone number is (972) 686-0369.

In December 1997, we entered into a Stock Purchase Agreement (the "Agreement") pursuant to which the Company issued 12,500,000 shares of our common stock in exchange for the conveyance to the Company of certain oil and gas properties by Calvin A. Wallen, III and his affiliates. In connection with the Agreement, three of the five members of the Board of Directors resigned and new directors were appointed, including Mr. Wallen, who also became President and CEO of the Company.

Prior to the Agreement, we focused primarily on the acquisition of non-operated working interests and overriding royalty interests in oil and gas properties. Subsequent to entering into the Agreement, we moved our headquarters from Tulsa, Oklahoma to Garland, Texas in order to utilize Mr. Wallen's assembled team of experienced management whose substantial expertise lay in acquisition, exploitation and development and the ability to manage both operated and non-operated oil and gas properties. In addition, after reviewing our existing property portfolio and refining our new business strategy, the management team initiated a divestment strategy to dispose of our non-strategic assets in non-core areas in order to concentrate on building core reserves. Pursuant to this strategy, we have acquired additional properties in our core areas, primarily in Louisiana, as well as pursuing an operated and a non-operated drilling program for the drilling of exploratory, development and infill wells, a strategy previously unavailable to us due to the technical expertise and experience required and the lack of available resources. At this time, we are not the operator for any of our properties. We believe that attractive opportunities remain for development of our remaining assets and acquisition of future assets.

On February 6, 2006, the Company entered into a Purchase Agreement with Tauren Exploration, Inc. ("Tauren"), an entity wholly owned by Mr. Wallen, with respect to the purchase by the Company of certain Cotton Valley leasehold interests (approximately 11,000 gross acres; 5,000 net acres) held by Tauren. Pursuant to the Purchase Agreement, the Company acquired from Tauren a 35% working interest in approximately 2,400 acres and a 49% working interest in approximately 8,500 acres located in DeSoto and Caddo Parishes, Louisiana, along with an associated Area of Mutual Interest ("AMI") and the right to acquire at "cost" (as defined in the Purchase Agreement) a working interest in all additional mineral leases obtained by Tauren in the AMI, in exchange for (a) \$3,500,000 in cash, (b) 2,500,000 shares of Company common stock, (c) an unsecured 12.5% short-term promissory note in the amount of \$1,300,000 and (d) a drilling credit of \$2,100,000.

On March 5, 2007, Cubic entered into a Credit Agreement with Wells Fargo Energy Capital ("Wells Fargo") providing for a revolving credit facility of \$20,000,000, and a convertible term loan of \$5,000,000 (the "Credit Facility"). In connection with entering into the Credit Facility, the Company issued to Wells Fargo warrants, with five-year expirations, for the purchase of up to 2,500,000 shares of Company common stock at an original exercise price of \$1.00 per share. The revolving note is subject to a borrowing base (the "Borrowing Base"), initially set at \$4,000,000. On July 27, 2007, Wells Fargo increased the Borrowing Base to \$6,600,000 in order to fund the drilling and casing costs of two new wells in the Company's Johnson Branch acreage in Caddo Parish, Louisiana. On September 7, 2007, Wells Fargo increased the Borrowing Base to \$8,600,000 in order to fund the remaining drilling and casing costs of five wells drilled since the beginning of fiscal 2008, the drilling and casing costs of two new wells, and the costs of installing a gathering/sales line and associated equipment in the Company's Johnson Branch acreage. On November 19, 2007, Wells Fargo increased the Borrowing Base to \$14,500,000 in order to fund the completion costs and

casing of eight wells already successfully drilled and the drilling of four additional wells located in the Company's Johnson Branch acreage. On May 8, 2008, Wells Fargo increased the Borrowing Base to \$20,000,000 in order to fund the completion costs and casing of the four wells located in the Company's Johnson Branch acreage (including two vertical wells drilled into the Bossier/Haynesville shales) and the drilling of two additional wells located in the Company's Bethany Longstreet acreage in Caddo and DeSoto Parishes. On December 18, 2009, the Company entered into a Second Amendment to Credit Agreement with Wells Fargo, providing for a revolving credit facility of up to \$40 million subject to Borrowing Base limits and a convertible term loan of \$5 million (the "Amended Credit Agreement"). The Borrowing Base under the revolving credit facility was initially established at \$25 million. The indebtedness bears interest at a fluctuating rate equal to the sum of the Wells Fargo Bank prime rate plus two percent (2%) per annum, matures on July 1, 2012 and is secured by substantially all of the assets of the Company. In connection with entering into the Amended Credit Agreement, the Company issued to Wells Fargo additional warrants, expiring on December 1, 2014, for the purchase of up to 5,000,000 shares of Company common stock at an exercise price of \$1.00 per share, and extended the expiration date of the warrants to purchase 2,500,000 shares of Company common stock that were previously issued to Wells Fargo to December 1, 2014.

In August 2010, we increased the revolver by \$5,000,000 from \$25,000,000 and our Borrowing Base and borrowings under the revolving credit facility to \$30 million. As of June 30, 2011, the revolver had \$30 million outstanding with a maturity date of July 1, 2012.

The terms of the Amended Credit Agreement, among other things, prohibit the Company from merging with another company or paying dividends, and limit additional indebtedness, sales of certain assets and investments. Upon the repayment in full of the indebtedness under the Amended Credit Agreement, and with respect to certain properties, upon the occurrence of the conditions set forth in Section 2.14 of the Amended Credit Agreement, the Company agreed to convey a net profits interest to Wells Fargo in an amount equal to 5% of Cubic's net interest in certain of its Louisiana properties.

On November 24, 2009, the Company entered into transactions with Tauren and Langtry Mineral & Development, LLC ("Langtry"), both of which are entities controlled by Mr. Wallen, under which the Company acquired \$30,952,810 in pre-paid drilling credits (the "Drilling Credits") applicable towards the development of its Haynesville Shale rights in Northwest Louisiana. As consideration for the Drilling Credits, the Company (a) conveyed to Tauren a net overriding royalty interest of approximately 2% in its leasehold rights below the Taylor Sand formation of the Cotton Valley and (b) issued to Langtry 10,350,000 Company common shares and preferred stock in the amount of \$10,350,000, convertible at any time prior to the fifth anniversary of issuance into Company common shares at \$1.20 per common share. The preferred stock is entitled to cumulative dividends equal to 8% per annum, payable quarterly, which dividends may be paid in cash or in additional shares of preferred stock, in the Company's discretion. The preferred stock may be redeemed by the Company at any time, at a redemption price equal to 20% over the original issue price.

As of June 30, 2011, the Company used the Drilling Credits to fund \$13,189,494 of its share of the drilling and completion costs for those horizontal Haynesville Shale wells drilled in sections previously operated by an affiliate of the Company which are now operated by third parties. As of June 30, 2011 a total of \$17,763,316 of the Drilling Credits remain. The counterparties (EXCO and BG) on the Drilling Credits have asserted certain offsets against their obligations under the Drilling Credits. We are aggressively defending our rights under the Drilling Credits. For additional information, see below under "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources".

On December 18, 2009, the Company issued a subordinated promissory note payable to Mr. Wallen, in the principal amount of \$2,000,000 (the "Wallen Note"). This note bears interest at the prime rate plus one percent (1%), with interest payable monthly. The outstanding principal balance is due and payable on September 30, 2012 and is subordinated to the indebtedness under the Amended Credit Agreement. The proceeds of the Wallen Note were used to repay a previously outstanding promissory note.

STRATEGY

Our strategy with respect to our domestic exploration program seeks to maintain a balanced portfolio of drilling opportunities that range from lower risk, field extension wells to the smaller scale pursuit of Company appropriate higher risk, high reserve potential prospects. Our focus is primarily on exploration opportunities that can benefit from advanced technologies, including 3-D seismic, designed to reduce risks and increase success rates. We develop prospects in-house with an affiliate and through strategic alliances with exploration companies that have expertise in specific target areas. In addition, we evaluate externally generated prospects and look to participate in certain of these opportunities to enhance our portfolio.

We are currently focusing our domestic exploration activities to develop our undeveloped leasehold opportunities in Louisiana. Currently we have exploration opportunities and seek to acquire additional leasehold interests in Caddo and DeSoto Parishes in Louisiana. These areas are a part of geologic studies utilizing regional trend surface analysis, 2-D and 3-D seismic data and/or vast sub-surface control. Prospects have been developed from approximately 4,000 to 12,000 feet in depth in the following reservoirs: Bossier/Haynesville shales; Cotton Valley; Hosston; Gloyd; Pettet; Glen Rose and Paluxy.

PRINCIPAL OIL AND GAS PROPERTIES

The following table summarizes certain information with respect to our principal areas of operation at June 30, 2011:

Area	Proved Reserves			Percent of Proved Reserves	Present Value (Discounted @ 10%)
	Oil & Natural Gas Liquids (Bbls)	Gas (Mcf)	Total Gas Equivalent (Mcf)		
Louisiana	1,199	57,692,086	57,699,279	100.0%	\$ 46,910,744
Texas	-	-	-	0.0%	-
Total	1,199	57,692,086	57,699,279	100.0%	\$ 46,910,744

Our Texas properties are situated in Eastland and Callahan Counties and represent an immaterial amount of reserves and are excluded from our SEC reserve report. Our Louisiana properties are situated in Caddo Parish and in DeSoto Parish. At June 30, 2011, the Louisiana properties contained substantially all of our proved reserves, a situation that is expected to continue, unless we are able to execute on our strategy to acquire additional oil and gas properties. The Texas properties consist primarily of wells acquired by the Company in several transactions between 1991 and 2002 and through overriding royalty interests reserved in farm-out agreements in 1998 and 1999. The vast majority of the Louisiana properties were acquired on or about October 1, 2004, January 11, 2005 and February 6, 2006.

Our net production for the fiscal year ended June 30, 2011 for all of the Company's wells averaged approximately 4,058 Mcf of natural gas per day, 4 barrels of oil per day and 145 gallons of natural gas liquids per day as compared to approximately 2,171 Mcf of natural gas per day, 4 barrels of oil per day and 105 gallons of natural gas liquids per day in the fiscal year ended June 30, 2010.

RECENT DEVELOPMENTS

Indigo Minerals has re-worked a well in Section 15-T15N-R15W and re-entered certain wells in the Cotton Valley formation in which the Company has interests. Indigo Minerals now operates the Cotton Valley wells previously operated by Chesapeake in which the Company has an interest.

Chesapeake has drilled and completed twelve horizontal Haynesville Shale wells on our acreage, most recently the Burford 21-H2 in Section 21-T14N-R15, the Western 18-H1 in Section 18-T15N-R16W and the Slaughter 6-H1 in Section 6-T15N-R15W. These wells were completed during fiscal 2011.

Petrohawk drilled and completed 1 horizontal Haynesville Shale well, during fiscal 2011, the DHD 35 H-1, located in Section 35-T16N-R15W of our acreage in the Johnson Branch field.

El Paso drilled and completed 1 horizontal Haynesville Shale well, the Fisher 20 H-1, in Section 20-T14N-R15W of our acreage in the Bethany Longstreet field during fiscal 2011.

EXCO has completed 2 wells, the Crow 8 H-1 in Section 8-T14N-R15W and the Crow 5 H-1 in Section 5-T14N-R15W, during fiscal 2011; both are located in the Bethany Longstreet field.

GAS GATHERING

Cubic has developed its infrastructure in Johnson Branch with approximately 16 miles of gathering lines and pipeline constructed for its currently producing wells and any further completions. In addition, a Johnson Branch tap, common point and compression facility were completed in November 2007 and are currently operational. The Company has also developed its infrastructure with approximately 7.8 miles of gathering lines and owns three taps in its Bethany Longstreet acreage.

MARKETING OF PRODUCTION

Crude Oil and Natural Gas

Our production consists mainly of natural gas. During fiscal 2011, we marketed our production of natural gas that was produced from wells operated by our affiliate Fossil Operating (“Fossil”), an entity controlled by our President and Chief Executive Officer, Calvin A. Wallen III, to three purchasers: (i) in Texas, Enbridge G & P, LP, and (ii) in Louisiana, EROC Gathering Company, LP and Atmos Energy Marketing, LLC (“Atmos Energy”). We sell our affiliate-operated crude oil and condensate (“NGL”) production at or near the well-site; although in some cases it is gathered by us or others and delivered to a central point of sale. Our crude oil and condensate production is transported by truck or by pipeline and is marketed by Transoil Marketing, Inc. (“Transoil”), Eastex Crude Company (“Eastex”), and Martin Gas Sales (“Martin”). During fiscal 2011, all of our production was generated by Fossil and seven third-party operators: Chesapeake, Indigo Minerals, EXCO, El Paso, BG, Petrohawk and Goodrich. Pursuant to the terms of our operating agreements, these third-party operators have the right to market our production from wells operating by them. Of these third-party producers, our total revenues during fiscal 2011 were generated as follows: EXCO – 66%, Chesapeake - 14% and Goodrich - 13%, with others producing 7%. Purchases by Atmos Energy through Fossil totaled 4% of our total revenues. We do not have any gas marketing agreements, commitments or contracts; we sell our crude oil, NGL and natural gas at the prevailing market prices. We have not engaged in crude oil hedging or trading activities. The majority of our production and our revenue is now generated by wells drilled and operated by non-affiliated third-party operators.

We believe we would be able to locate alternate purchasers in the event of the loss of any of these purchasers, and that any such loss would not have a material adverse effect on our financial condition or results of operations. Revenue totaled \$6,133,299 for fiscal 2011 primarily from the sale of natural gas. Natural gas totaled \$5,928,198 and represented 97%, oil totaled \$120,030 and represented 2% and NGL totaled \$85,071 and represented 1% of our total oil and gas revenues, respectively for fiscal 2011.

Price Considerations

Natural gas and natural gas liquids prices in the geographical areas in which we operate are closely tied to established price indices which are heavily influenced by national and regional supply and demand factors and the futures price per MMBtu for natural gas delivered at Henry Hub, Louisiana established on the NYMEX (“NYMEX-Henry Hub”). At times, these indices correlate closely with the NYMEX-Henry Hub price, but often there are significant variances between the NYMEX-Henry Hub price and the indices used to price our natural gas. Average natural gas prices received by us in each of our operating areas generally fluctuate with changes in these established indices. The average natural gas price per Mcf received by us in fiscal 2011 was \$4.00 as compared to \$4.21 in fiscal 2010. The average natural gas liquids price per gallon received by us in fiscal 2011 was \$1.60 compared to \$1.27 in fiscal 2010. Crude oil prices are established in

a highly liquid, international market, with average crude oil prices that we receive generally fluctuating with changes in the futures price established on the NYMEX for West Texas Intermediate Crude Oil (“NYMEX-WTI”). The average crude oil price per barrel received by us in fiscal 2011 was \$83.13 as compared to \$73.18 in fiscal 2010.

OIL AND GAS RESERVES

The following tables set forth our proved developed and proved undeveloped reserves at June 30, 2011, the estimated future net cash flows from such proved reserves and the Standardized Measure of Discounted Future Net Cash Flows attributable to our proved reserves at June 30, 2011, 2010 and 2009:

Category	Oil & Natural Gas Liquids (Bbls)	Gas (Mcf)	Total Gas Equivalent (Mcfe)	Estimated Future Net Cash Flows	10% Discount
Proved Producing	1,199	3,672,716	3,679,909	\$12,478,219	\$9,248,784
Proved Non-Producing	-	2,961,520	2,961,520	11,045,430	9,169,470
Proved Developed Reserves	1,199	6,634,236	6,641,429	\$ 23,523,649	\$ 18,418,254
Proved Undeveloped	-	51,057,850	51,057,850	63,411,720	\$28,492,490
Total Proved Reserves	1,199	57,692,086	57,699,279	\$ 86,935,369	\$ 46,910,744

	At June 30,		
	2011	2010	2009
Proved Developed Reserves:			
Oil & Natural Gas Liquids (Bbls)	1,199	1,166	2,968
Gas (Mcf)	6,634,236	2,666,610	337,993
Mcfe	6,641,429	2,673,604	355,801
Estimated future net cash flows (before income tax)	\$ 23,523,649	\$ 9,632,270	\$ 956,021
Standardized Measure (1)	\$ 18,418,254	\$ 7,924,620	\$ 781,820
Proved Undeveloped Reserves:			
Oil & Natural Gas Liquids (Bbls)	-	7,481	123,241
Gas (Mcf)	51,057,850	26,490,670	19,981,634
Mcfe	51,057,850	26,535,556	20,721,079
Estimated future net cash flows (before income tax)	\$ 63,411,720	\$ 81,104,850	\$ 25,860,200
Standardized Measure (1)	\$ 28,492,490	\$ 56,832,670	\$ 10,020,570
Total Proved Reserves:			
Oil & Natural Gas Liquids (Bbls)	1,199	8,647	126,209
Gas (Mcf)	57,692,086	29,157,280	20,319,627
Mcfe	57,699,279	29,209,160	21,076,880
Estimated future net cash flows (before income tax)	\$ 86,935,369	\$ 90,737,120	\$ 26,816,221
Standardized Measure (1)	\$ 46,910,744	\$ 64,757,290	\$ 10,802,390
Average price used to calculate reserves:			
Oil (per Bbl)	\$ 87.24	\$ 70.08	\$ 66.52
Natural Gas Liquids (per Bbl)	\$ 1.57	\$ 1.25	\$ 1.02
Gas (per Mcf)	\$ 4.53	\$ 5.08	\$ 3.72

(1) The Standardized Measure of Discounted Future Net Cash Flows prepared by the Company represents the present value (using an annual discount rate of 10%) of estimated future net cash flows from the production of proved reserves, without giving effect to the future income tax expense. See “Note J - Oil and gas reserves information (unaudited)” in the Notes to the Financial Statements of the Company included elsewhere in this Report for additional information regarding the disclosure of the Standardized Measure information in accordance with the provisions of Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 932, Extractive Activities – Oil and Gas.

During fiscal 2011, we incurred total expenditures of \$7.4 million relating to development and exploration activities that resulted in 5,945,586 Mcf of proved undeveloped reserves being converted to proved developed. We have not held any of our proved undeveloped reserves for longer than five years. All reserve information is located in the Haynesville Shale and Cotton Valley plays in Louisiana.

The information set forth in this Annual Report relating to our proved reserves, estimated future net cash flows and present values is taken from reports prepared by Cambrian Consultants America, Inc., d/b/a RPS ("RPS"), an independent petroleum engineering firm, for fiscal years 2011, 2010 and 2009. The reservoir engineer at RPS who oversaw the preparation of the reserve estimates has a Master's of Science Degree in Geology, is certified by the State of Texas Professional Geologists as a Licensed Geologist and has thirty-two years of experience in the upstream oil and gas industry. The estimates of this independent petroleum engineering firm were based upon review of production histories and other geological, economic, ownership and engineering data provided by the Company. Information with respect to our reserves in Texas as of June 30, 2011, was prepared in-house, was not reviewed by an independent engineering firm, and due to the immaterial size was not reported in Cubic's reserve report for the period ended June 30, 2011. Cubic's internal geologist reviews all data that is provided to RPS for the reserve reports. He has a Master's of Science Degree in Geology, is an American Association of Petroleum Geologists' Certified Petroleum Geologist and has twenty-eight years of experience in the upstream oil and gas industry. He also reviews and approves the reports from RPS. In accordance with guidelines of the SEC, our estimates of proved reserves and the future net revenues from which present values are derived are made using an average price mechanism based on the first day of each of the last twelve months and a differential based on amount per Mcf received, by the Company. Operating costs, development costs and certain production-related taxes were deducted in arriving at estimated future net cash flows, but such costs do not include debt service or general and administrative expenses.

There are numerous uncertainties inherent in estimating oil and gas reserves and their values, including many factors beyond our control. The reserve data set forth in this Annual Report represents estimates only. Reservoir engineering is a subjective process of estimating the sizes of underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development, exploitation and exploration activities, prevailing oil and gas prices, operating costs and other factors, which revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. There can be no assurance that these estimates are accurate predictions of our oil and gas reserves or their values. Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves.

The estimates of proved reserves at June 30, 2011, 2010, and 2009 were prepared by our independent petroleum consultant, RPS, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The technical persons responsible for preparing the reserve estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our policies and practices regarding internal control over the estimating of reserves are structured to objectively and accurately estimate our oil and natural gas reserves quantities and present values in compliance with the SEC's regulations and U.S. Generally Accepted Accounting Principles. We maintain an internal staff of petroleum engineers and geosciences professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of data furnished to RPS in its reserves estimation process. Inputs to our reserves estimation process are based on historical results for production history, oil and natural gas prices, lease operating expenses, development costs, ownership interest and other

required data. Our technical team meets regularly with representatives of RPS to review properties and discuss methods and assumptions used in RPS's preparation of the year-end reserves estimates. While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, our senior management reviews and approves the RPS reserve report and any internally estimated significant changes to our proved reserves on a timely basis.

Costs Incurred

The following table shows certain information regarding the costs incurred by us in our property acquisition, development and exploratory activities during the periods indicated.

	Year Ended June 30,		
	2011	2010	2009
Property acquisition costs	\$ 448,432	\$ 1,777,848	\$ 72,385
Exploratory costs	-	-	5,928,825
Development costs	10,175,986	6,988,115	-
Total	<u>\$ 10,624,418</u>	<u>\$ 8,765,963</u>	<u>\$ 6,001,210</u>

Drilling Results

We drilled or participated in the drilling of wells as set out in the table below for the periods indicated. The table was completed based upon the date drilling completed. We did not acquire any wells during these periods. You should not consider the results of prior drilling activities as necessarily indicative of future performance, nor should you assume that there is necessarily any correlation between the number of productive wells drilled and the oil and natural gas reserves generated by those wells.

	Year Ended June 30,					
	2011		2010		2009	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Development wells:						
Productive	7	1.51	10	1.07	-	-
Dry	-	-	-	-	-	-
Total development	<u>7</u>	<u>1.51</u>	<u>10</u>	<u>1.07</u>	<u>-</u>	<u>-</u>
Exploratory wells:						
Productive	-	-	-	-	6	0.82
Dry	-	-	-	-	-	-
Total exploratory	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>6</u>	<u>0.82</u>
Total wells:						
Productive	7	1.51	10	1.07	6	0.82
Dry	-	-	-	-	-	-
Total wells	<u>7</u>	<u>1.51</u>	<u>10</u>	<u>1.07</u>	<u>6</u>	<u>0.82</u>

NET PRODUCTION, SALES PRICES AND COSTS

The following table presents certain information with respect to production, prices and costs attributable to all oil and gas property interests owned by us for the fiscal years ended June 30, 2011, 2010 and 2009:

	Year Ended June 30,		
	2011	2010	2009
Production Volumes:			
Oil (Bbl)	1,444	1,364	1,681
Natural gas liquids (gallons)	53,008	38,411	77,772
Natural gas (Mcf)	1,481,430	792,433	279,516
Total oil, natural gas liquids, and natural gas (Mcfe)	1,497,666	806,102	300,712
Weighted Average Sales Prices:			
Oil (per Bbl)	\$ 83.13	\$ 73.18	\$ 60.00
Natural gas liquids (per gallon)	\$ 1.60	\$ 1.27	\$ 1.12
Natural gas (per Mcf)	\$ 4.00	\$ 4.21	\$ 5.98
Selected Expenses per Mcfe:			
Production costs	\$ 0.60	\$ 1.27	\$ 3.98
Workover expenses (non-recurring)	\$ 0.01	\$ 0.05	\$ 0.12
Severance taxes	\$ 0.07	\$ 0.15	\$ 0.20
Other revenue deductions	\$ 0.56	\$ 0.65	\$ 0.27
Total lease operating expenses	\$ 1.24	\$ 2.13	\$ 4.57
General and administrative expenses	\$ 2.11	\$ 2.95	\$ 6.45
Depreciation, depletion and amortization	\$ 2.48	\$ 1.41	\$ 2.55

PRODUCTIVE WELLS AND ACREAGE

Productive Wells

The following table sets forth our productive wells at June 30, 2011:

Oil		Gas		Total	
Gross	Net	Gross	Net	Gross	Net
-	-	58	13.47	58	13.47

We have no oil wells at this time. The oil we produce is a by-product of our gas wells.

Acreage

The following table sets forth our undeveloped and developed gross and net leasehold acreage at June 30, 2011. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

Undeveloped		Developed		TOTAL	
Gross	Net	Gross	Net	Gross	Net
-	-	13,239	5,149	13,239	5,149

As is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except as to claims made by, through or under the transferor. Although we have title to developed acreage examined prior to acquisition in those cases in which the economic significance of the acreage justifies the cost, there can be no assurance that losses will not result from title defects or from defects in the assignment of leasehold rights.

OPERATIONS

Oil and gas properties are customarily operated under the terms of a joint operating agreement, which provides for reimbursement of the operator's direct expenses and monthly per well supervision fees. Per well supervision fees vary widely depending on the geographic location and producing formation of the well, whether the well produces oil or gas and other factors. The majority of our production is operated by non-affiliated third-party operators. The balance of our production is operated by Fossil, an entity wholly owned by Mr. Wallen.

We have contract relationships with petroleum engineers, geologists and other operations and production specialists who believe the production rates and reserves will increase, which would lower the cost per Mcfe of operating our affiliated and non-affiliated third-party oil and gas properties.

EMPLOYEES

At September 9, 2011, the Company had ten (10) employees, eight (8) full-time and two (2) part-time. We regularly use independent consultants and contractors to perform various professional services, including well-site supervision, design, construction, permitting and environmental assessment. We use independent contractors to perform field and on-site production operation services.

FACILITIES

The Company's principal executive and administrative offices are located at 9870 Plano Road, Dallas, Texas, and are owned by an affiliate controlled by Mr. Wallen. The offices were leased on a month-to-month basis for an average monthly amount charged to the Company, from July 1, 2010 until December 31, 2010, of \$2,229. Effective January 1, 2011, the Company signed a 2-year lease that charges the Company a monthly fee of \$8,000 per month. The Company believes that there is other appropriate space available in the event the Company should terminate its current leasing arrangement, though the Company believes the monthly rental fee would likely exceed \$8,000 per month.

COMPETITION

Currently our acreage is being operated by affiliated and non-affiliated third-party operators. There is limited, if any competition in this non-operated position, so our focus is on reducing costs and expenses where possible. We have in the past operated and developed oil and natural gas plays and our strategy is to operate and develop additional properties, in the future. In that environment, we compete with major integrated oil and natural gas companies and independent oil and natural gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which could adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have operated for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Recent increased oil and natural gas drilling activity in East Texas and Northwest Louisiana has resulted in increased demand for drilling rigs and other oilfield equipment and services. At various times, we have and may continue to experienced temporary or prolonged shortages or unavailability of drilling rigs, drill pipe and other material used in oil and gas drilling and completing. Such unavailability could result in increased

costs, delays in timing of anticipated development or cause interests in undeveloped oil and natural gas leases to lapse.

REGULATION

Exploration and Production. The exploration, production and sale of oil and natural gas are subject to various types of local, state and federal laws and regulations. These laws and regulations govern a wide range of matters, including the drilling and spacing of wells, allowable rates of production, restoration of surface areas, plugging and abandonment of wells and requirements for the operation of wells. Our operations are also subject to various conservation requirements. These include the regulation of the size and shape of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of oil and natural gas properties. In this regard, some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratable production. All of these regulations may adversely affect the rate at which wells produce oil and natural gas and the number of wells we may drill. All statements in this report about the number of locations or wells reflect current laws and regulations.

Laws and regulations relating to our business frequently change, and future laws and regulations, including changes to existing laws and regulations, could adversely affect our business.

Environmental Matters. The discharge of oil, gas or other pollutants into the air, soil or water may give rise to liabilities to the government and third parties and may require us to incur costs to remedy or control such discharges. Natural gas, oil or other pollutants, including salt water brine, may be discharged in many ways, including from a well or drilling equipment at a drill site, leakage from pipelines or other gathering and transportation facilities, leakage from storage tanks and sudden discharges from damage or explosion at natural gas facilities or oil and natural gas wells. Discharged hydrocarbons may migrate through soil to water supplies or adjoining property, giving rise to additional liabilities.

A variety of federal and state laws and regulations govern the environmental aspects of natural gas and oil production, transportation and processing and may, in addition to other laws, impose liability in the event of discharges, whether or not accidental, failure to notify the proper authorities of a discharge, and other noncompliance with those laws. Compliance with such laws and regulations may increase the cost of oil and natural gas exploration, development and production; although we do not anticipate that compliance will have a material adverse effect on our capital expenditures or earnings. Failure to comply with the requirements of the applicable laws and regulations, by us or our third-party operators could subject us to substantial civil and/or criminal penalties and to the temporary or permanent curtailment or cessation of all or a portion of our operations.

The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as the “superfund law,” imposes liability, regardless of fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of a disposal site or sites where the release occurred and companies that dispose or arrange for disposal of the hazardous substances found at the time. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and severable liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We could be subject to liability under CERCLA because our drilling and production activities generate relatively small amounts of liquid and solid waste, which could be subject to classification as hazardous substances under CERCLA.

The Resource Conservation and Recovery Act of 1976, as amended (“RCRA”), is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a “generator” or

“transporter” of hazardous waste or an “owner” or “operator” of a hazardous waste treatment, storage or disposal facility. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

The federal Water Pollution Control Act of 1972, as amended (“Clean Water Act”), and analogous state laws, impose restrictions and strict controls regarding the discharge of pollutants into certain water bodies. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into waters of the United States or, under state law, state surface or subsurface waters. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate operating protocols including containment berms and similar structures to help prevent the contamination of regulated waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities or during construction activities.

Our third-party operators employ hydraulic fracturing techniques to stimulate natural gas production from unconventional geological formations, which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. The federal Energy Policy Act of 2005 amended the Underground Injection Control (“UIC”) provisions of the federal Safe Drinking Water Act (“SDWA”) to exclude hydraulic fracturing from the definition of “underground injection” under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. Similar legislation could be introduced in the current session of Congress. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a study of the potential environmental impacts of hydraulic fracturing, the results of which are anticipated to be available by late 2012. Last year, a committee of the U.S. House of Representatives commenced investigations into hydraulic fracturing practices. The U.S. Department of the Interior has announced that it will consider regulations relating to the use of hydraulic fracturing techniques on public lands and disclosure of fracturing fluid constituents. In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. Our current operations have been concentrated largely in Louisiana, and we do not currently have operations on federal lands or in the states where the most stringent proposals have been advanced. However, if new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, or if we acquire oil and gas properties in areas subject to those regulations, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business. It is also possible that our drilling and injection operations could adversely affect the environment, which could result in a requirement to perform investigations or clean-ups or in the incurrence of other unexpected material costs or liabilities.

The Oil Pollution Act of 1990, as amended (“OPA”), which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A “responsible party” under the OPA includes owners and operators of certain onshore facilities from which a release may affect regulated waters.

The federal Clean Air Act, as amended (“Clean Air Act”), and state air pollution permitting laws, restrict the emission of air pollutants from many sources, including processing plants and compressor stations and potentially from our drilling and production operations, and as a result affects oil and natural gas operations.

We may be required to incur compliance costs or capital expenditures for existing or new facilities to remain in compliance. In addition, more stringent regulations governing emissions of air pollutants, including greenhouse gases such as methane (a component of natural gas) and carbon dioxide are being developed by the federal government, and may increase the costs of compliance for some facilities or the cost of transportation or processing of produced oil and gas which may affect our operating costs. Obtaining permits has the potential to delay the development of oil and natural gas projects. While we may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, we do not believe, based on current law, that such requirements will have a material adverse effect on our operations.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases from industrial and energy sources contribute to increases of carbon dioxide levels in the earth's atmosphere and oceans, effects on climate, and other environmental effects and therefore present an endangerment to public health and the environment, the EPA has adopted various regulations under the federal Clean Air Act addressing emissions of greenhouse gases that may affect the oil and gas industry. On November 8, 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry, including certain onshore oil and natural gas production activities, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, the EPA has taken the position that existing Clean Air Act provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective. Such changes will affect state air permitting programs in states that administer the Clean Air Act under a delegation of authority, including states in which we have operations. In the last Congress, numerous legislative measures were introduced that would have imposed restrictions or costs on greenhouse gas emissions, including from the oil and gas industry. It is uncertain whether similar measures will be introduced in, or passed by, the current Congress. In addition, the United States has been involved in international negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change. In addition, certain U.S. states or regional coalitions of states have adopted measures regulating or limiting greenhouse gases from certain sources or have adopted policies seeking to reduce overall emissions of greenhouse gases. The adoption and implementation of any international treaty or federal or state legislation or regulations, imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to comply with such requirements and possibly require the reduction or limitation of emissions of greenhouse gases associated with our operations. Such legislation or regulations could adversely affect demand for the oil and natural gas we produce or the cost of transportation and processing our production. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases may produce changes in climate or weather, such as increased frequency and severity of storms, floods and other climatic events, which if any such effects were to occur, could have adverse physical effects on our exploration and production operations or associated infrastructure or disrupt markets for our products.

The federal Endangered Species Act, as amended ("ESA"), and comparable state laws, may restrict activities that affect endangered and threatened species or their habitats. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state laws, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. These laws and provisions of CERCLA require reporting of spills and releases of hazardous chemicals in certain situations.

We do not believe that our environmental, health and safety risks will be materially different from those of comparable U.S. companies in the oil and natural gas industry. Nevertheless, there can be no assurance that such environmental, health and safety laws and regulations will not result in a curtailment of production or material increase in the cost of production, development or exploration or otherwise adversely affect our capital expenditures, financial condition and results of operations.

In addition, because we have acquired and may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

Natural Gas Marketing and Transportation. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the Federal Energy Regulatory Commission (“FERC”). The FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines’ traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC’s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC’s pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

In addition, the FERC is continually proposing and implementing new rules affecting segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to FERC’s jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation.

The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach established by the FERC under Order No. 637 will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers with which we compete.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC, the Commodity Futures Trading Commission, or the CFTC, and/or the Federal Trade Commission, or the FTC. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Crude Oil Marketing and Transportation. Our sales of crude oil and condensate are currently not regulated and are made at market prices. Nevertheless, Congress could reenact price controls in the future.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect

our operations in any way that is materially different from those of our competitors who are similarly situated.

Further, intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry, many of which are used in this Report.

“**Bbl**” means a barrel of 42 U.S. gallons, used herein in reference to oil or other liquid hydrocarbons.

“**Bcf**” means one billion cubic feet.

“**Bcfe**” means Bcf of natural gas equivalent; determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

“**Btu**” means British thermal unit, which means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

“**Casing**” means a type of pipe that is used for encasing a smaller diameter carrier pipe for installation in a well. Casing is used to send off fluids from the hole or keep a hole from caving in.

“**Completion**” means the installation of permanent equipment for the production of oil or gas.

“**Compressor Station**” means a facility in which the pressure of natural gas is raised to facilitate its transmission through pipelines.

“**Condensate**” means hydrocarbons naturally occurring in the gaseous phase in a reservoir that condense to become a liquid at the surface due to the change in pressure and temperature.

“**Cubic Foot**” means the volume of gas that fills one cubic foot of space under standard temperature and pressure conditions. Standard pressure is 14.73 psi and standard temperature is 60 degrees Fahrenheit.

“**Developed Acreage**” means the number of acres that are allocated or assignable to producing wells or wells capable of production.

“**Development Drilling**” or “**Development Well**” means 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**” or “**Dry Well**” means a well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion as an oil and gas well.

“**Estimated Future Net Cash Flows**” means estimated future gross cash flows to be generated from the production of proved reserves, net of estimated production, future development costs, and future abandonment costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization.

“Exploration” is the act of searching for potential sub-surface reservoirs of gas or oil. Methods include the use of magnetometers, gravity meters, seismic exploration, surface mapping, and the drilling of exploratory test wells (known as “wildcats”).

“Exploratory Drilling” or **“Exploratory Well”** means a well drilled to find and produce oil or gas reserves not classified as proved, to find a new production reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

“Fracture Stimulation” means a stimulation treatment routinely performed involving the injection of water, sand and chemicals under pressure to stimulate hydrocarbon production in low-permeability reservoirs.

“Farm-In” or **“Farm-Out”** means an agreement pursuant to which the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in” and the assignor issues a “farm-out.”

“Finding and Development Costs” means the total costs incurred for exploration and development activities (excluding exploratory drilling in progress and drilling inventories), divided by total proved reserve additions. To the extent any portion of the proved reserve additions consist of proved undeveloped reserves; additional costs would have to be incurred in order for such proved undeveloped reserves to be produced. This measure may differ from the measure used by other oil and natural gas companies.

“Gas” means natural gas.

“Full Cost Pool” The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

“Gathering System” means a system of pipelines, compressor stations and any other related facilities that gathers natural gas from a supply region and transports it to the major transmission systems.

“Gross” when used with respect to acres or wells, means the total acres or wells in which we have a working interest.

“Held-by-production” A provision in an oil, gas and mineral lease that perpetuates a company’s right to operate a property or concession as long as the property or concession produces a minimum paying quantity of oil or gas.

“Horizontal Drilling” means drilling a well that deviates from the vertical and travels horizontally through a prospective reservoir.

“Horizontal Wells” Wells which are drilled at angles greater than 70 degrees from vertical.

“Hydrocarbons” means an organic chemical compound of hydrogen and carbon. Hydrocarbons are a large class of liquid, solid or gaseous organic compounds, which are the basis of almost all petroleum products.

“Infill drilling” means drilling of a well between known producing wells to better exploit the reservoir.

“Initial production rate” means generally, the maximum 24 hour production volume from a well.

“Lease” means a formal agreement between two or more parties where the owner of the land grants another party the right to drill and produce hydrocarbons in exchange for payment.

“Mcf” means one thousand cubic feet.

“**Mmcf/d**” means one million cubic feet of natural gas per day.

“**Mcfe**” means Mcf of natural gas equivalent; determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

“**MMbtu**” means one million Btus.

“**MMcf**” means one million cubic feet.

“**MMcfe**” means MMcf of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

“**Natural Gas Liquids**” means liquid hydrocarbons which have been extracted from natural gas (e.g., ethane, propane, butane and natural gasoline).

“**Net**” when used with respect to acres or wells, refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by the Company.

“**Net Production**” means production that is owned by the Company less royalties and production due others.

“**NYMEX**” means the New York Mercantile Exchange.

“**Overriding royalty interest**” means an interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

“**Operator**” means the individual or company responsible for the exploration, development and production of an oil or gas well or lease.

“**Play**” means a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

“**Pipeline**” means all parts of a physical facility through which gas is transported, including pipe, valves and other appendages attached to the pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

“**Present Value**”, “**PV-10**” or “**Standardized Measure**” when used with respect to oil and gas reserves, is the pre-tax present value, discounted at an annual rate of 10%, of the estimated future gross revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the SEC, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation (except to the extent a contract specifically provides otherwise), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization.

“**Productive Wells**” or “**Producing Wells**” consist of producing wells and wells capable of production, including natural gas wells waiting on pipeline connections.

“**Proved Reserves**” means those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

“Recompletion” means an operation within an existing well bore to make the well produce oil and/or gas from a different, separately producible zone other than the zone from which the well had been producing.

“Reserves” means proved reserves.

“Reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“Royalty” means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner’s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

“Sandstone” means rock composed mainly of sand-sized particles or fragments of the mineral quartz, which, because these grains are rigid, will withstand tremendous pressures without being compacted.

“Shale” means a type of rock composed of common clay or mud. When clay is compacted under great pressure and temperature deep in the earth, water contained in the clay is expelled, and clay turns into shale.

“2-D Seismic” means an advanced technology method by which a cross-section of the earth’s subsurface is created through the interpretation of reflecting seismic data collected along a single source profile.

“3-D Seismic” means an advanced technology method by which a three dimensional image of the earth’s subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, development and production.

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

“Undeveloped Reserves” means reserves of any category 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.

“Working Interest” means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties.

“Workovers” means operations on a producing well to restore or increase production.

AVAILABILITY OF INFORMATION

We file annual, quarterly and current reports and proxy statements with the Securities and Exchange Commission (the “SEC”). The public may read and copy any materials we file with the SEC at the SEC’s Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. We file our reports with the SEC electronically. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding Cubic Energy, Inc. and other companies that file electronically with the SEC.

Our website address is www.cubicenergyinc.com. We make available on our website free of charge copies of our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Item 1A. Risk Factors.

You should carefully consider the following risk factors, in addition to the other information set forth in this Report, in connection with any investment decision regarding shares of our common stock. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock. Some information in this Report may contain “forward-looking” statements that discuss future expectations of our financial condition and results of operation. The risk factors noted in this section and other factors could cause our actual results to differ materially from those contained in any forward-looking statements.

Fluctuations in oil and natural gas prices, which have been volatile at times, may adversely affect our revenues as well as our ability to maintain or increase our borrowing capacity, repay current or future indebtedness and obtain additional capital.

Our future financial condition, access to capital, cash flow and results of operations depend upon the prices we receive for our oil and natural gas. We are particularly dependent on prices for natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Factors that affect the prices we receive for our oil and natural gas include:

- the level of domestic production;
- the availability of imported oil and natural gas;
- political and economic conditions and events in foreign oil and natural gas producing nations, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the cost and availability of transportation and pipeline systems with adequate capacity;
- the cost and availability of other competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and refined products;
- concerns about global warming or other conservation initiatives and the extent of governmental price controls and regulation of production;
- weather;
- foreign and domestic government relations; and
- overall economic conditions, particularly the recent worldwide economic slowdown which has put downward pressure on oil and natural gas prices and demand.

In the past, prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. During fiscal 2011, the Henry Hub spot price for natural gas fluctuated from a high of \$4.94 per Mcf to a low of \$3.18 per Mcf, while the NYMEX West Texas Intermediate crude oil price ranged from a high of \$113.39 per Bbl to a low of \$71.24 per Bbl.

Our revenues, cash flow and profitability and our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital depend substantially upon oil and natural gas prices.

EXCO Operating Company, LP (“EXCO”) and BG US Production Company, LLC (“BG”) claim that they have no further obligations to us under the Drilling Credits. If this dispute is resolved in favor of EXCO

and BG, we will be required to fund our share of drilling and completion costs on wells operated by EXCO and BG from other sources, or we could incur substantial penalties.

During November 2009, we acquired \$30.9 million of pre-paid Drilling Credits from EXCO applicable towards payment of our share of the drilling and completion costs for horizontal Haynesville Shale wells in Northwest Louisiana that were to be operated by EXCO. Subsequently, EXCO assigned to BG certain of its rights and obligations with respect to the properties transferred to EXCO in exchange for the Drilling Credits. On May 18, 2011, EXCO and BG sent a letter to us claiming that they have no further obligations under the Drilling Credits. At the time of their letter, the remaining balance of the Drilling Credits was approximately \$18 million. We intend to vigorously defend our rights to the remaining balance of the Drilling Credits. We entered into mediation with respect to this matter, but no resolution was achieved. Subsequently, we filed a demand to have this matter resolved through binding arbitration, as provided in the agreement governing the issuance of the Drilling Credits. We have filed a court action to compel arbitration.

If we are not successful in defending our rights to the Drilling Credits, we could be required to fund our share of the drilling and completion costs for horizontal Haynesville Shale wells operated by EXCO and BG on a current basis, or we could be forced to go “non-consent” on current and future wells. If we are not able to fund those costs, thereby being deemed to be non-consent, we would incur significant penalties, which would significantly reduce our revenues from these wells. In addition, we would be required to pay royalty owners their share of revenues, which we estimate would be approximately \$590,000 during fiscal 2012. Reductions in our revenues, or the requirement to pay royalty owners, could have a material adverse effect on our results of operations, financial position and cash flows.

We face significant competition, and many of our competitors have resources in excess of our available resources.

The oil and gas industry is highly competitive. We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of producing properties and exploratory prospects and sale of crude oil, natural gas and natural gas liquids. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies with substantially larger operating staffs and greater capital resources than us. Such companies may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Exploratory drilling is a speculative activity that may not result in commercially productive reserves and may require expenditures in excess of budgeted amounts.

Drilling activities are subject to many risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. There can be no assurance that new wells drilled by us or in which we have an interest will be productive or that we will recover all or any portion of our investment. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control, including economic conditions, mechanical problems, pressure or irregularities in formations, title problems, weather conditions, compliance with governmental requirements and shortages in or delays in the delivery of equipment and services. Such equipment shortages and delays sometimes involve drilling rigs where inclement weather prohibits the movement of land rigs causing a high demand for rigs by a large number of companies during a relatively short period of time. Our future drilling activities may not be successful. Lack of drilling success could have a material adverse effect on our financial condition and results of operations.

Our operations are also subject to all the hazards and risks normally incident to the development, exploitation, production and transportation of, and the exploration for, oil and gas, including unusual or

unexpected geologic formations, pressures, down hole fires, mechanical failures, blowouts, explosions, uncontrollable flows of oil, gas or well fluids and pollution and other environmental risks. These hazards could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. We participate in insurance coverage maintained by the operators of our wells, although there can be no assurances that such coverage will be sufficient to prevent a material adverse effect to us if any of the foregoing events occur.

We may not identify all risks associated with the acquisition of oil and natural gas properties, or existing wells, and any indemnifications we receive from sellers may be insufficient to protect us from such risks, which may result in unexpected liabilities and costs to us.

Our business strategy focuses on acquisitions of undeveloped oil and natural gas properties that we believe are capable of production. We may make additional acquisitions of undeveloped oil and gas properties from time to time, subject to available resources. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and other liabilities and other factors. Generally, it is not feasible for us to review in detail every individual property involved in a potential acquisition. In making acquisitions, we generally focus most of our title and valuation efforts on the properties that we believe to be more significant, or of higher-value. Even a detailed review of properties and records may not reveal all existing or potential problems, nor would it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. In addition, we do not inspect in detail every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we perform a detailed inspection. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable or may be limited by floors and caps, and the financial wherewithal of such seller may significantly limit our ability to recover our costs and expenses. Any limitation on our ability to recover the costs related any potential problem could materially impact our financial condition and results of operations.

We have a history of operating losses and may not be profitable. If we are not able to achieve and maintain profitability in the future, we might not be able to access funds through debt or equity financings.

We incurred losses of \$(11,149,991) and \$(5,176,625) for the fiscal years ended June 30, 2011 and 2010, respectively. Our accumulated deficit as of June 30, 2011 was \$(65,540,677). Historically, we have funded our operating losses, acquisitions and drilling costs primarily through a combination of private offerings of convertible debt, senior secured debt, and equity securities. We have no assurance that we will be able to obtain an increase in our borrowing base to permit us to access any of the remaining \$10,000,000 capacity under our current Wells Fargo Credit Agreement. By July 1, 2012, we must repay or refinance all amounts payable to Wells Fargo under the Credit Agreement. Our success in obtaining the necessary capital resources to fund the repayment to Wells Fargo as well as future costs associated with our operations and drilling plans is dependent upon our ability to: (i) increase revenues through acquisitions and recovery of our proved producing and proved developed non-producing oil and gas reserves; (ii) maintain effective cost controls at the corporate administrative office and in field operations; and (iii) obtain additional financing. However, even if we achieve some success with our plans, there can be no assurance that we will be able to generate sufficient revenues to achieve significant profitable operations or to fund our drilling plans.

We have substantial capital requirements necessary for undeveloped properties for which we may not be able to obtain adequate financing.

The majority of our oil and gas reserves are undeveloped. At June 30, 2011, we had proved undeveloped reserves of 51,057,850 Mcfe, which represent approximately 89% of our total proved reserves of 57,699,279 Mcfe. Recovery of the Company's future undeveloped reserves will require significant capital expenditures to further develop these reserves during fiscal 2012 and for the foreseeable future. No assurance can be given that our financing sources will be sufficient to fund our costs for third-party operators' development activities or that development activities will be either successful or in accordance with our schedule. Additionally, any failure to see increases in natural gas prices or any significant increase in the cost of development could result in a significant reduction in the number of wells drilled and/or reworked. No assurance can be given that any wells will produce oil or gas in commercially profitable quantities.

As of June 30, 2011, we had a Drilling Credit balance of \$17,763,316 with EXCO and BG to fund the drilling and completion of Company acreage being operated by EXCO or BG. EXCO and BG claim that they have no further obligations under the Drilling Credits. Once this Drilling Credit is exhausted, or earlier if we are not successful in defending our rights to the Drilling Credits, we will be obligated to pay our share of the drilling and completion costs for wells operated by EXCO and BG on our acreage, on a current basis. Further, we maintain material leaseholds in units operated by Goodrich, Chesapeake, El Paso, Petrohawk and Indigo Minerals and it is expected that we will be required to expended significant monies in the near term in order to participate in the drilling and completion of wells operated by these other companies.

Development of our properties will require additional capital resources. There can be no assurance that sufficient cash on hand or additional financing (on either favorable or unfavorable terms) will be available, when required, to fund the development. Any inability to obtain additional financing could have a material adverse effect on us, including requiring us to cease our oil and gas development plans or not being able to maintain our working interest due to failure to pay our share of expenses. Any additional financing may involve substantial dilution to the interests of our stockholders at that time.

We are subject to uncertainties in reserve estimates and future net cash flows.

This report contains estimates of our oil and gas reserves and the expected future net cash flows from those reserves, most of which have been prepared by an independent petroleum consultant. There are numerous uncertainties inherent in estimating quantities of reserves of oil and gas and in projecting future rates of production and the timing of development expenditures, including many factors beyond our control. The reserve estimates in this report are based on various assumptions, including, for example, constant oil and gas prices, operating expenses, capital expenditures and the availability of funds, and, therefore, are inherently imprecise indications of future net cash flows. Actual future production, cash flows, taxes, operating expenses, development expenditures and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of reserves set forth in this report. Additionally, our reserves may be subject to downward or upward revision based upon actual production performance, results of future development and exploration, prevailing oil and gas prices and other factors, many of which are beyond our control.

The present value of future net reserves discounted at 10% (the "PV-10") of proved reserves referred to in this report should not be construed as the current market value of the estimated proved reserves of oil and gas attributable to our properties. In accordance with applicable requirements of the SEC, the estimated discounted future net cash flows from proved reserves are based on an average price of the first day of each month of the last 12 months and a differential of the price per Mcf received by the Company, and costs as of the date of the estimate, whereas actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by: (i) the timing of both production and related expenses; (ii) changes in consumption levels; and (iii) governmental regulations or taxation. In addition, the calculation of the present value of the future net cash flows using a 10% discount as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the oil and gas industry in general. Furthermore, our reserves may be subject to downward or upward revision based upon actual production, results of future development, supply and demand for oil and gas, prevailing oil and gas prices and other factors. See "Item 1. Business – Oil and Gas Reserves."

We are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues.

Our oil and gas business involves a variety of operating risks, including, but not limited to, unexpected formations or pressures, uncontrollable flows of oil, gas, brine or well fluids into the environment (including groundwater contamination), blowouts, fires, explosions, pollution and other risks, any of which could result in personal injuries, loss of life, damage to properties and substantial losses. Although we carry insurance at levels that we believe are reasonable, we are not fully insured against all risks. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on our financial condition and operations.

From time to time, due primarily to contract terms, pipeline interruptions or weather conditions, the producing wells in which we own an interest have been subject to production curtailments. The curtailments range from production being partially restricted to wells being completely shut-in. The duration of curtailments varies from a few days to several months. In most cases, we are provided only limited notice as to when production will be curtailed and the duration of such curtailments.

We cannot control the development of the properties we own but do not operate, which may adversely affect our production, revenues and results of operations.

As of June 30, 2011, third parties operate wells that represent almost all of our proved reserves. As a result, the success and timing of our drilling and development activities on those properties depend upon a number of factors outside of our control, including:

- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in drilling wells; and
- the selection of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines, which may adversely affect our production, revenues and results of operations.

New SEC and GAAP reserve reporting requirements may affect the results of our reserve estimates and could change our relative positioning in the industry with regard to reserve estimates.

On December 31, 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting", amending and expanding its disclosure requirements for oil and natural gas producing companies. The new rules and disclosure requirements were effective as of December 31, 2009. On January 16, 2010, the Financial Accounting Standards Board adopted rules conforming GAAP to the new SEC definitions and rules. These changes are the first major modifications to the accounting-based reserve reporting requirements since 1982. Among other things, the new SEC rules modify various definitions impacting categories of oil and natural gas reserves and replace the previous pricing mechanism of using the last day of our fiscal year by using an average price mechanism based on the first day of each of the last twelve months for purposes of computing reserve quantities as of December 31, 2009 and subsequent periods. In addition, these new requirements not only require oil and gas companies to report proved reserves, but also permit voluntary disclosure of 'probable' and 'possible' reserves. While the new rules are intended to provide investors with a more complete picture of the reserves of reporting companies, and were made with an eye towards continuing to recognize new technologies and knowledge about the geology and extent of oil and natural gas fields, these changes will potentially affect the results of our reserve estimates and application of these new reserve reporting rules by competitors may change our relative positioning in the industry as a whole with regards to reserve estimates.

Our business may suffer if we lose key personnel.

We depend to a large extent on the services of Calvin A. Wallen, III, our President, Chairman of the Board, and Chief Executive Officer. The loss of the services of Mr. Wallen would have a material adverse effect on our operations. We have not obtained key personnel life insurance on Mr. Wallen.

Certain of our affiliates control a majority of our outstanding common stock, which may affect other stockholders' ability to influence matters submitted to a vote of stockholders.

As of September 9, 2011, our executive officers, directors and their affiliates and certain 5% stockholders hold approximately 51.7% of our outstanding shares of common stock. As a result, officers, directors and their affiliates and such stockholders have the ability to exert significant influence or control over our business affairs, including the ability to control the election of directors and results of voting on all matters requiring stockholder approval. This concentration of voting power may delay or prevent a potential change in control.

Certain of our affiliates have engaged in business transactions with the Company, which may result in conflicts of interest.

Certain officers, directors and related parties, including entities controlled by Mr. Wallen, the President, Chairman of the Board and Chief Executive Officer, have engaged in business transactions with the Company which were not the result of arm's length negotiations between independent parties. Our management believes that the terms of these transactions were as favorable to us as those that could have been obtained from unaffiliated parties under similar circumstances. All future transactions between us and our affiliates will be on terms no less favorable than could be obtained from unaffiliated third parties and will be approved by a majority of the independent members of our Board of Directors.

The liquidity, market price and volume of our stock are volatile.

Our common stock is traded on the NYSE Amex, LLC (the "AMEX"). The liquidity of our common stock may be adversely affected, and purchasers of our common stock may have difficulty selling our common stock, if our common stock does not continue to trade on the AMEX or another suitable trading market. The AMEX maintains certain minimum continued listing standards. If we are not able to continue to satisfy the continued listing standards, or qualify for an exemption to such standards, then we could be subject non-compliance status or de-listing.

The trading price of our common stock could be subject to wide fluctuations in response to quarter-to-quarter variations in our operating results, announcements of our drilling results and other events or factors. In addition, the U.S. stock markets have from time to time experienced extreme price and volume fluctuations that have affected the market price for many companies and which often have been unrelated to the operating performance of these companies. These broad market fluctuations may adversely affect the market price of our securities.

We may experience adverse consequences because of required indemnification of officers and directors.

Provisions of our Certificate of Formation and Bylaws provide that we will indemnify any director and officer as to liabilities incurred in their capacity as a director or officer and on those terms and conditions set forth therein to the fullest extent of Texas law. Further, we may purchase and maintain insurance on behalf of any such persons whether or not we would have the power to indemnify such person against the liability insured against. The foregoing could result in substantial expenditures by us and prevent any recovery from our officers, directors, agents and employees for losses incurred by us as a result of their actions.

Certain anti-takeover provisions may discourage a change in control.

Provisions of Texas law and our Certificate of Formation and Bylaws may have the effect of delaying or preventing a change in control or acquisition of the Company. Our Certificate of Formation and Bylaws include “blank check” preferred stock (the terms of which may be fixed by our Board of Directors without stockholder approval), and certain procedural requirements governing stockholder meetings. These provisions could have the effect of delaying or preventing a change in control of the Company.

We do not intend to declare cash dividends on Common Stock in the foreseeable future.

Our Board of Directors presently intends to retain all of our earnings for the repayment of debt, the payment of dividends on our preferred stock and the expansion of our business. We therefore do not anticipate the distribution of cash dividends on our common stock in the foreseeable future. Any future decision of our Board of Directors to pay cash dividends on our common stock will depend, among other factors, upon our earnings, financial position and cash requirements.

Our internal controls over financial reporting may not be effective, which could have a significant and adverse effect on our business.

Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC, which we collectively refer to as Section 404, require us to evaluate our internal controls over financial reporting to allow management to report on those internal controls as of the end of each year. Effective internal controls are necessary for us to produce reliable financial reports and are important in our effort to prevent financial fraud. In the course of our Section 404 evaluations, we may identify conditions that may result in significant deficiencies or material weaknesses and we may conclude that enhancements, modifications or changes to our internal controls are necessary or desirable. Implementing any such matters would divert the attention of our management, could involve significant costs, and may negatively impact our results of operations.

We note that there are inherent limitations on the effectiveness of internal controls, as they cannot prevent collusion, management override or failure of human judgment. If we fail to maintain an effective system of internal controls or if management or our independent registered public accounting firm were to discover material weaknesses in our internal controls, we may be unable to produce reliable financial reports or prevent fraud, and it could harm our financial condition and results of operations, result in a loss of investor confidence and negatively impact our share price.

We may not have satisfactory title or rights to all of our current or future properties.

Prior to acquiring undeveloped properties, our contract land professionals review title records or other title review materials relating to substantially all of such properties. The title investigation performed by us prior to acquiring undeveloped properties is thorough, but less rigorous than that conducted prior to drilling, consistent with industry standards. Prior to drilling, we obtain a title opinion on the drill site prior to drilling. However, a title opinion does not necessarily ensure satisfactory title. We believe we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. In the normal course of our business, title defects and lease issues of varying degrees arise, and, if practicable, reasonable efforts are made to cure such defects and issues.

At June 30, 2011, we believe that our leaseholds for all of our net acreage were being kept in force by virtue of production in paying quantities. The majority of our acreage is in Northwest Louisiana, and the legal climate in Northwest Louisiana has become increasingly hostile and litigious towards oil and gas companies. Many mineral owners are seeking opportunities to make additional money from their minerals rights, including pursuit of claims of lease expiration by asserting that production does not exist in paying quantities. We are a defendant in a lawsuit brought by a mineral owner alleging, among other things, that all or part of our mineral lease lapsed. If the outcome of this lawsuit were to be determined entirely in favor of

the mineral owner, our total acreage position could decrease by a maximum of 17%. We are vigorously defending our position in this lawsuit.

Governmental regulations could adversely affect our business.

Our business is subject to certain federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and natural gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste and other matters. These laws and regulations have increased the costs of our operations. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

Laws and regulations relating to our business frequently change, and future laws and regulations, including changes to existing laws and regulations, could adversely affect our business.

In particular and without limiting the foregoing, various tax proposals currently under consideration could result in an increase and acceleration of the payment of federal income taxes assessed against independent oil and natural gas producers, for example by eliminating the ability to expense intangible drilling costs, removing the percentage depletion allowance and increasing the amortization period for geological and geophysical expenses. Any of these changes would increase our tax burden.

The States of Texas and Louisiana and many other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration for and production of oil and gas. Such states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of such wells. The statutes and regulations of these states limit the rate at which oil and gas can be produced from our properties. However, we do not believe we will be affected materially differently by these statutes and regulations than any other similarly situated oil and gas company.

Environmental liabilities could adversely affect our business.

In the event of a release of oil, natural gas or other pollutants from our operations into the environment, we could incur liability for any and all consequences of such release, including personal injuries, property damage, cleanup costs and governmental fines. We could potentially discharge these materials into the environment in several ways, including:

- from a well or drilling equipment at a drill site;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering and explosions.

In addition, because we may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination that we have not yet discovered relating to the acquired properties or any of our other properties.

To the extent we incur any environmental liabilities; it could adversely affect our results of operations or financial condition.

Climate change legislation, regulation and litigation could materially adversely affect us.

There is an increased focus by local, state and national regulatory bodies on greenhouse gas (“GHG”) emissions and climate change. Various regulatory bodies have announced their intent to regulate GHG emissions, including the United States Environmental Protection Agency, which promulgated several GHG regulations in 2010 and late 2009. As these regulations are under development or are being challenged in the courts, we are unable to predict the total impact of these potential regulations upon our business, and it is possible that we could face increases in operating costs in order to comply with GHG emission legislation.

Passage of legislation or regulations that regulate or restrict emissions of GHG, or GHG-related litigation instituted against us or our customers, could result in direct costs to us and could also result in changes to the consumption and demand for natural gas and carbon dioxide produced from our oil and natural gas properties, any of which could have a material adverse effect on our business, financial position, results of operations and prospects.

Horizontal drilling activities could be subject to increased regulation and could expose us to environmental risks that could adversely affect us.

Legislation relating to horizontal drilling activities that could impose new permitting disclosure or other environmental restrictions or obligations on our operations is currently being considered at the federal level, and may in the future be considered at the state or local level. In particular, the U.S. Congress recently signaled a renewed interest in certain downhole injection activities, some of which we utilize in our operations. The focus may lead to new legislation or regulations that could affect our operations. Any additional requirements or restrictions on our operations could result in delays, increased operating costs or a requirement to change or eliminate certain drilling and injection activities in a manner that may materially adversely affect us. In addition, because horizontal drilling involves fracture stimulation through the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production, it is also possible that our drilling and the fracturing process could adversely affect the environment, which could result in a requirement to perform investigations or clean-ups or in the incurrence of other unexpected material costs or liabilities.

We may be responsible for additional costs in connection with abandonment of properties.

We are responsible for payment of plugging and abandonment costs on our oil and gas properties pro rata to our working interest. Based on our experience, we anticipate that the ultimate aggregate salvage value of lease and well equipment located on our properties will exceed the costs of abandoning such properties. There can be no assurance, however, that we will be successful in avoiding additional expenses in connection with the abandonment of any of our properties. In addition, abandonment costs and their timing may change due to many factors, including actual production results, inflation rates and changes in environmental laws and regulations.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is included in “Part I. Item 1. Business” and is incorporated herein by reference.

Item 3. Legal Proceedings.

We are party to lawsuits arising in the normal course of business. We intend to defend these actions vigorously and believe, based on currently available information, that adverse results or judgments from such actions, if any, will not be material to our financial position or results of operations. The majority of our acreage is in Northwest Louisiana and the legal climate in Northwest Louisiana has become increasingly hostile and litigious towards oil and gas companies. Many mineral owners are seeking opportunities to make additional money from their mineral rights, including pursuit of claims of lease expiration by asserting that production does not exist in paying quantities. In the normal course of our business, title defects and lease issues of varying degrees will arise, and, if practicable, reasonable efforts will be made to cure any such defects and issues.

A lawsuit was filed on or about June 15, 2010, styled, “Gloria’s Ranch, LLC v. Tauren Exploration, Inc., Cubic Energy, Inc., Wells Fargo Energy Capital, Inc. & EXCO USA Asset, LLC”, filed in the 1st Judicial District Court, Caddo Parish, Louisiana, Cause No. 541-768, A. This lawsuit alleges that all or part of the Gloria’s Ranch mineral lease has lapsed, and seeks a finding that the mineral lease has lapsed, damages, attorney fees, and other equitable relief. This lawsuit would have a material effect, of a maximum of 17%, on the acreage position of the Company if ultimately adjudicated entirely in favor of the mineral owner. The Company intends to vigorously defend its position and believes it will prevail regarding a majority, if not all, of the acreage at issue in this lawsuit.

On May 18, 2011, EXCO and BG informed the Company that they do not intend to honor the balance of the Drilling Credits, which was approximately \$18 million at that time. The Company believes that there is no valid basis to dispute the remaining balance of the Drilling Credits. This dispute was submitted to mediation on August 26, 2011, but was not resolved. The Company has submitted this dispute to binding arbitration, and has filed a court action in District Court in Dallas County, Texas to compel such arbitration. The Company intends to continue to vigorously defend its rights to the remaining balance of the Drilling Credits.

Item 4. (Removed and Reserved).

PART II

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

Common Stock and Market

The common stock of the Company is traded on the AMEX under the trading symbol "QBC". At September 9, 2011, there were 76,815,908 shares of common stock outstanding held by approximately 799 stockholders of record.

Under its Amended and Restated Certificate of Formation, the Company is authorized to issue one class of up to 120,000,000 common shares, par value \$0.05 per share, and one class of up to 10,000,000 preferred shares, par value \$0.01 per share. As of September 9, 2011, there were 109,123 preferred shares of the Company outstanding.

Common Stock Price Range

The following table shows, for the periods indicated, the range of high and low sales price information for our common stock on the AMEX. Any market for our common stock should be considered sporadic, illiquid and highly volatile. Our common stock's trading range during the periods indicated was as follows:

<u>Fiscal Year 2010</u>	<u>High</u>	<u>Low</u>
1st Quarter	\$1.18	\$0.94
2nd Quarter	\$1.70	\$0.89
3rd Quarter	\$1.40	\$1.02
4th Quarter	\$1.15	\$0.81
<u>Fiscal Year 2011</u>	<u>High</u>	<u>Low</u>
1st Quarter	\$1.04	\$0.70
2nd Quarter	\$1.05	\$0.55
3rd Quarter	\$1.19	\$0.70
4th Quarter	\$0.76	\$0.49

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

Through the exercises of warrants, between January 7 and January 19, 2011, the Company issued an aggregate of 954,315 shares of common stock. Aggregate proceeds to the Company of the aforementioned stock issuances were \$642,780, all of which has been or is expected to be used for working capital purposes.

On November 30, 2010, the Board of Directors of the Company increased the number of directors of the Company and appointed David B. Brown and Paul R. Ferretti to fill the vacancies created by such increase, in accordance with the provisions of the Company's bylaws. The Board authorized stock grants of 3,507 shares of our common stock to each of Messrs. Brown and Ferretti, which number of shares is equal to the number of shares granted to other non-management directors for calendar year 2010, on a prorated basis, with an aggregate market value of the common stock granted of \$4,418 based on at the last sale price (\$0.63 per share) on the aforementioned date, on the AMEX of the Company's common stock. Such amounts were recorded as compensation expense upon issuance.

On January 18, 2011, the Company issued 460,000 shares of common stock to seven directors of the Company pursuant to the Plan. As of such date, the aggregate market value of the common stock granted

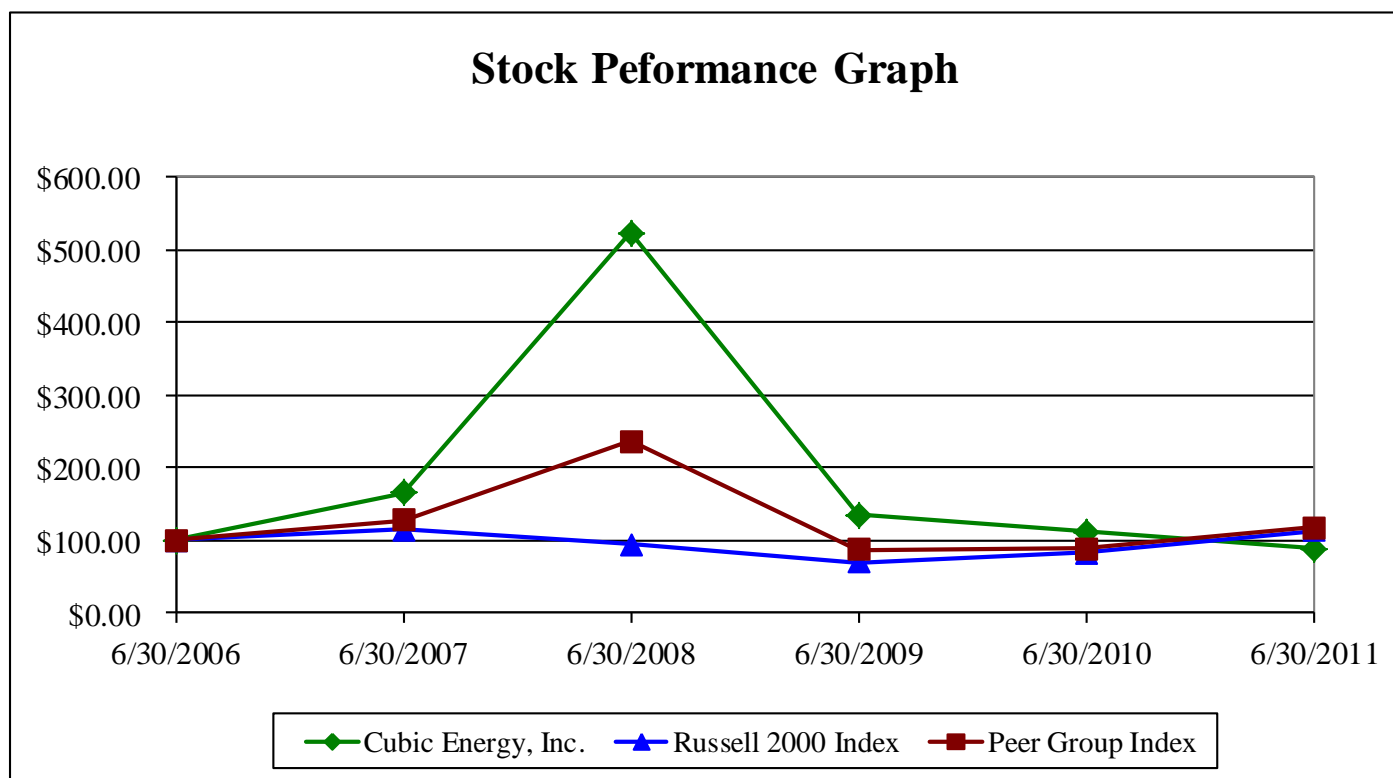
was \$538,200 based on the last sale price (\$1.17 per share) on January 11, 2011, on the AMEX of the Company's common stock. Such amount was expensed upon issuance to compensation expense.

The aforementioned issuances were made in reliance upon an exemption from registration set forth in Section 4(2) of the Securities Act of 1993, as amended, which exempts transactions by an issuer not involving a public offering.

We did not purchase any of our equity securities during the fourth quarter of fiscal 2011.

Stockholder Return Performance Graph

The following graph compares the cumulative total stockholder return on our common stock during the five years ended June 30, 2011 with the cumulative total stockholder return of the Russell 2000 Index and a peer group of 14 oil and gas exploration and production companies comprised of Abraxas Petroleum Corporation, GMX Resources Inc., Petrohawk Energy Corporation, Chesapeake Energy Corporation, Goodrich Petroleum Corporation, Northern Oil & Gas Inc., Comstock Resources Inc., EXCO Resources Inc., Penn Virginia Corporation, Quicksilver Resources Inc., Range Resources Corporation, Southwestern Energy Company, Delta Petroleum Corporation, and SM Energy Company (collectively referred to as the "Peer Group Index"). The comparison assumes an investment of \$100 on June 30, 2006 in each of our common stock, the Russell 2000 Index and the Peer Group Index.



	<u>6/30/2006</u>	<u>6/30/2007</u>	<u>6/30/2008</u>	<u>6/30/2009</u>	<u>6/30/2010</u>	<u>6/30/2011</u>
Cubic Energy, Inc.	\$ 100.00	\$ 166.25	\$ 523.75	\$ 135.00	\$ 112.50	\$ 88.75
Russell 2000 Index	\$ 100.00	\$ 115.05	\$ 95.17	\$ 70.14	\$ 83.42	\$ 114.18
Peer Group Index	\$ 100.00	\$ 127.82	\$ 236.38	\$ 87.75	\$ 89.73	\$ 118.37

Dividend Policy

We have neither declared nor paid any dividends on our common stock since our inception. Presently, we intend to retain our earnings, if any, to provide funds for expansion of our business. Therefore, we do not anticipate declaring or paying cash dividends on our common stock in the foreseeable future. Any future dividends on our common stock will be subject to the discretion of our Board of Directors and will depend upon, among other things, future earnings, our operating and financial condition, our capital requirements, debt obligation agreements, general business conditions and other pertinent factors. Moreover, the terms of the Amended Credit Agreement prohibit the payment of dividends on our common stock.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of June 30, 2011 with respect to compensation plans (including individual compensation arrangements) under which equity securities of the registrant are authorized for issuance:

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of shares of common stock remaining available for future issuance under equity compensation plans
2005 Stock Option Plan approved by shareholders	288,667	\$ 1.20	2,558,139
Equity compensation plans not approved by shareholders	-	\$ -	-
Total	<u>288,667</u>		<u>2,558,139</u>

Item 6. Selected Financial Data.

The following table presents a summary of our financial information for the periods indicated. It should be read in conjunction with our Financial Statements and related notes (beginning on page F-1 at the end of this report) and other financial information included herein.

(In thousands, except per share data)	Year ended June 30,				
	2011	2010	2009	2008	2007
Statements of Operations Data:					
Total oil and gas sales revenues	\$ 6,133	\$ 3,486	\$ 1,858	\$ 2,302	\$ 583
Costs and expenses:					
Oil and gas production, operating and development costs	1,858	1,845	1,372	1,163	481
General and administrative expenses	3,157	2,389	1,940	2,488	1,325
Depreciation, depletion and amortization	3,707	1,153	772	2,152	362
Impairment loss on oil and gas properties	-	-	20,391	-	1,791
Total costs and expenses	<u>8,722</u>	<u>5,387</u>	<u>24,475</u>	<u>5,803</u>	<u>3,958</u>
Operating income (loss)	(2,588)	(1,901)	(22,617)	(3,501)	(3,376)
Non-operating income (expense):					
Other income, net	8	5	34	46	38
Interest expense, net	(7,649)	(4,714)	(2,045)	(1,580)	(1,279)
Amortization of loan costs	(60)	(73)	(135)	(94)	(101)
Total non-operating income (expense)	<u>(7,701)</u>	<u>(4,783)</u>	<u>(2,146)</u>	<u>(1,628)</u>	<u>(1,342)</u>
Loss on extinguishment of debt, net	-	1,748	-	-	(1,083)
Loss from operations before income taxes	(10,289)	(4,937)	(24,763)	(5,129)	(5,801)
Income tax expense (benefit)	-	-	-	-	-
Net income (loss)	<u>\$ (10,289)</u>	<u>\$ (4,937)</u>	<u>\$ (24,763)</u>	<u>\$ (5,129)</u>	<u>\$ (5,801)</u>
Dividends on preferred shares	<u>\$ (861)</u>	<u>\$ (240)</u>			
Net loss available to common shareholders	<u>\$ (11,150)</u>	<u>\$ (5,177)</u>			
Net loss per common share - basic and diluted	<u>\$ (0.15)</u>	<u>\$ (0.08)</u>	<u>\$ (0.40)</u>	<u>\$ (0.09)</u>	<u>\$ (0.12)</u>
Weighted average common shares outstanding	76,049	67,584	61,150	56,974	50,338
Statements of Cash Flow Data:					
Cash provided by (used in) operating activities	\$ (2,567)	\$ (682)	\$ (2,152)	\$ (1,234)	\$ (1,802)
Cash provided by (used in) investing activities	\$ (1,412)	\$ (5,736)	\$ (5,589)	\$ (15,513)	\$ (4,052)
Cash provided by (used in) financing activities	\$ 5,130	\$ 6,738	\$ 5,668	\$ 15,768	\$ 8,717
Balance Sheet Data (at end of period):					
Working capital (deficit)	\$ 2,320	\$ (1,436)	\$ (27,823)	\$ 1,747	\$ 2,607
Oil and gas properties, and equipment, net	\$ 15,840	\$ 8,923	\$ 11,710	\$ 26,858	\$ 13,666
Total assets	\$ 37,057	\$ 38,196	\$ 12,127	\$ 29,491	\$ 18,108
Long-term liabilities, net of discounts	\$ 31,197	\$ 20,984	\$ -	\$ 22,971	\$ 7,627
Total liabilities	\$ 32,262	\$ 24,434	\$ 2,815	\$ 23,632	\$ 9,313
Shareholders' equity	\$ 4,795	\$ 13,762	\$ (16,023)	\$ 5,858	\$ 8,795

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our financial statements and the related notes to those statements included elsewhere in this Annual Report on Form 10-K. In addition to historical financial information, the following discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our results and the timing of selected events may differ materially from those anticipated in these forward-looking statements as a result of many factors, including those discussed under “risk factors” and elsewhere in this Annual Report on Form 10-K.

Overview

Cubic Energy, Inc. is an independent upstream energy company engaged in the development and production of, and exploration for, crude oil and natural gas. Our oil and gas assets and activities are concentrated exclusively in Louisiana and Texas.

Our corporate strategy with respect to our asset acquisition and development efforts was to position the Company in a low risk opportunity while building main stream high yield reserves. The acquisition of our Cotton Valley acreage in DeSoto and Caddo Parishes, Louisiana, put us in a reservoir rich environment both in the Cotton Valley and Bossier/Haynesville Shale formations, and gives us the potential to discover additional commercial horizons that can add value to the bottom line. We have had success on our acreage with wells drilled by achieving production from not only the Cotton Valley and Bossier/Haynesville Shale formations, but also the Hosston formations.

Summary Operating, Reserve and Other Data

The following table presents an unaudited summary of certain operating and oil and natural gas reserve data, and non-GAAP financial data for the periods indicated:

	Year ended June 30,				
	2011	2010	2009	2008	2007
Operating Data:					
Proved Reserves (Bcfe)	57.7	29.2	21.1	6.6	4.3
Production (Mcf)	1,497,666	806,102	300,712	244,665	76,214
Producing wells at end of period, gross	58	40	43	32	22
Producing wells at end of period, net	13.47	11.81	21.44	18.42	14.42
Acreage, gross	13,239	13,594	14,466	14,711	17,542
Acreage, net	5,149	5,324	6,077	6,151	7,364
Production:					
Oil (Bbl)	1,444	1,364	1,681	1,682	967
Natural gas (Mcf)	1,481,430	792,433	279,516	228,219	70,412
Natural gas liquids (gallons)	53,008	38,411	77,772	44,476	-
Total oil, gas and liquids (Mcf)	1,497,664	806,100	300,712	244,665	76,214
Average daily (Mcf)	4,103	2,208	824	668	209
Weighted Average Sales Prices:					
Oil (per Bbl)	\$ 87.24	\$ 70.08	\$ 66.52	\$ 102.15	\$ 61.68
Natural gas (per Mcf)	\$ 4.53	\$ 5.08	\$ 3.72	\$ 9.01	\$ 7.44
Natural gas liquids (per gallon)	\$ 1.57	\$ 1.25	\$ 1.02	\$ 1.66	n/a
Natural gas equivalent (per Mcfe)	\$ 4.10	\$ 4.32	\$ 6.18	\$ 9.41	\$ 7.65
Selected Expenses per Mcfe:					
Production costs	\$ 0.60	\$ 1.27	\$ 3.98	\$ 3.60	\$ 4.18
Workover expenses (non-recurring)	\$ 0.01	\$ 0.05	\$ 0.12	\$ 0.11	\$ 1.40
Severance taxes	\$ 0.07	\$ 0.15	\$ 0.20	\$ 0.29	\$ 0.39
Other revenue deductions	\$ 0.56	\$ 0.65	\$ 0.27	\$ 0.75	\$ 0.35
Total lease operating expenses	\$ 1.24	\$ 2.12	\$ 4.57	\$ 4.75	\$ 6.32
General and administrative expenses:					
Non-cash stock-based compensation	\$ 0.38	\$ 0.49	\$ 1.28	\$ 5.13	\$ 6.43
Other general and administrative	\$ 1.72	\$ 2.47	\$ 5.17	\$ 5.04	\$ 10.96
Total general and administrative	\$ 2.10	\$ 2.96	\$ 6.45	\$ 10.17	\$ 17.39
Depreciation, depletion and amortization	\$ 2.48	\$ 1.43	\$ 2.55	\$ 8.79	\$ 4.76

RESULTS OF OPERATIONS

Comparison of Fiscal 2011 to Fiscal 2010

Revenues

OIL AND GAS SALES increased 76% to \$6,133,299 for fiscal 2011 from \$3,486,171 for fiscal 2010 primarily due to increased gas volumes resulting from 19 new Haynesville Shale wells, of which eleven are operated by Chesapeake, three are operated by Goodrich and five are operated by EXCO. This increase was mitigated by the average price of natural gas being \$4.14 per Mcf for fiscal 2011 and \$4.32 per Mcf for fiscal 2010.

Costs and Expenses

OIL AND GAS PRODUCTION, OPERATING AND DEVELOPMENT COSTS (also referred to as "LEASE OPERATING EXPENSES" elsewhere herein) increased 1% to \$1,857,528 (30% of oil and gas sales) for fiscal 2011 from \$1,845,153 (53% of oil and gas sales) for fiscal 2010.

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A") increased 32% to \$3,156,860 for fiscal 2011 from \$2,389,073 in fiscal 2010. This increase of \$767,787 was primarily due to increased stock compensation of \$178,235, franchise tax increase of \$159,604, contract landmen increase of \$75,888, a one-time legal settlement of \$82,500 and overall increased marketing expenses of the Company, which includes travel expense increase of \$24,610, office supplies increase of \$10,888, reserve reports increase of \$29,567 and maps and logs increase of \$20,355.

DEPRECIATION, DEPLETION AND AMORTIZATION ("DD&A") increased 222% to \$3,707,255 in fiscal 2011 from \$1,153,065 in fiscal 2010, primarily due to an increase in projected capital costs of \$94,022,190 caused by a 20% increase in well costs and an increase in the total number of offset wells allowed per section, which costs were added to the full cost pool, thereby increasing amortization, which is based on the unit-of-production method.

GAIN ON DEBT EXTINGUISHMENT was \$0 for fiscal 2011 and was \$1,747,623 for fiscal 2010.

INTEREST EXPENSE, INCLUDING AMORTIZATION OF LOAN DISCOUNT increased 62% to \$7,648,622 in fiscal 2011 from \$4,714,386 in fiscal 2010 primarily due to an increase in debt (before discounts) to \$37,000,000 at June 30, 2011 from \$32,000,000 at June 30, 2010. This increase resulted from the drawing down of our revolving credit line of \$5,000,000 (before discounts) of our Amended Wells Fargo Credit Facility. The weighted average debt balance (before discounts) for fiscal 2011 was \$36,164,384 as compared to \$29,616,438 in fiscal 2010. The Credit Facility with Wells Fargo also resulted in a loan discount being recorded. The discount is being amortized over the original three-year term of the debt as additional interest expense with \$5,740,440 being recorded in fiscal 2011 as compared to \$3,178,416 in fiscal 2010. There was a decrease in the capitalization of interest expense to the full cost pool for oil and gas properties of \$5,221 in fiscal 2011 as compared to \$12,737 in fiscal 2010.

Comparison of Fiscal 2010 to Fiscal 2009

Revenues

OIL AND GAS SALES increased 88% to \$3,486,171 for fiscal 2010 from \$1,858,139 for fiscal 2009 primarily due to increased gas volumes resulting from 14 new Haynesville Shale wells, of which nine are operated by Chesapeake, three are operated by Goodrich and two are operated by EXCO, Inc. This increase was mitigated by the average price of natural gas being \$4.32 per Mcf for fiscal 2010 and \$6.18 per Mcf for fiscal 2009.

Costs and Expenses

OIL AND GAS PRODUCTION, OPERATING AND DEVELOPMENT COSTS (also referred to as "LEASE OPERATING EXPENSES" elsewhere herein) increased 34% to \$1,845,153 (53% of oil and gas sales) for fiscal 2010 from \$1,372,041 (74% of oil and gas sales) for fiscal 2009 primarily due to more wells being on-line in Louisiana, which resulted in: a \$439,379 increase in costs passed-through to the Company by the purchaser of the Company's gas, a \$65,000 increase in production taxes and a \$53,660 increase in non-operated property expenses. These increases were somewhat offset by a \$151,724 decrease in common facility costs and \$128,098 decrease in salt water hauling.

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A") increased 23% to \$2,389,073 for fiscal 2010 from \$1,940,025 in fiscal 2009 as a result of: a \$128,965 increase in marketing expense, a \$165,597 increase in legal fees due in part to the support needed to address the AMEX non-compliance issue discussed below, related expenses in connection with the November 2009 transaction between the Company, Tauren and Langtry and costs of amending the Wells Fargo Credit Facility. There was also a \$63,054 increase in contracted professional services; \$20,000 of which went to NYSE Amex non-compliance support and \$23,000 went to Sarbanes-Oxley 404 compliance.

On June 26, 2009, the Company received a letter from AMEX stating that the Company was not in compliance with Section 1003(a)(iv) of AMEX's Company Guide because AMEX believed that it appeared questionable, in its opinion, as to whether the Company would be able to continue operations and/or meet its obligations as they mature. On March 5, 2010, the Company received notice from AMEX that the Company had regained full compliance. The Company was able to regain full compliance by executing the compliance plan submitted to AMEX that included the measures taken by the Company to acquire the Drilling Credits and restructuring the Company's debt with Wells Fargo through the Second Amendment.

DEPRECIATION, DEPLETION AND AMORTIZATION ("DD&A") increased 49% to \$1,153,065 in fiscal 2010 from \$771,861 in fiscal 2009 primarily due to an increase in capital expenditures in fiscal 2010 related to the non-operated development of oil and gas properties.

IMPAIRMENT OF OIL AND GAS PROPERTIES decreased to \$0 in fiscal 2010 from \$20,390,819 in fiscal 2009. The fiscal 2009 impairment resulted from a downward revision of our reserve estimates, which was effected by the following events: (i) we experienced delays related to third party providers in our Bethany Longstreet acreage, including not receiving contracted-for compression services, which temporarily delayed our ability to produce from these wells; (ii) we did not effectuate final completion of certain wells due to a shift in our focus to the development of our Johnson Branch acreage in Caddo Parish, Louisiana; and, (iii) the lack of production history in wells recently brought online lead to a sharper decline curve being utilized by RPS in formulating the reserve estimates.

GAIN ON DEBT EXTINGUISHMENT was realized in December 2009 as a result of the refinancing of the debt with Wells Fargo. The existing loan balance of \$1,877,494 was decreased (written off) as a term of the amendment of the Wells Fargo credit facility that was extinguished, which was partially offset by debt extinguishment costs of \$129,871. This created an overall gain on debt extinguishment of \$1,747,623 for fiscal 2010.

INTEREST EXPENSE, INCLUDING AMORTIZATION OF LOAN DISCOUNT increased 131% to \$4,714,386 in fiscal 2010 from \$2,044,718 in fiscal 2009 primarily due to an increase in debt (before discounts) to \$32,000,000 at June 30, 2010 from \$27,000,000 at June 30, 2009. This increase resulted from the drawing down of our revolving credit line of \$5,000,000 (before discounts) of our Amended Wells Fargo Credit Facility. The weighted average debt balance (before discounts) for fiscal 2010 was \$29,616,438 as compared to \$26,565,452 in fiscal 2009. The Credit Facility with Wells Fargo also resulted in a loan discount being recorded. The discount is being amortized over the original three-year term of the debt as additional interest expense with \$3,178,416 being recorded in fiscal 2010 as compared to \$514,620 in fiscal 2009. There was a decrease in the capitalization of interest expense to the full cost pool for oil and gas properties of \$12,737 in fiscal 2010 as compared to \$30,682 in fiscal 2009.

Liquidity and Capital Resources

Overview

The Company's primary resource is its oil and gas reserves.

On November 24, 2009, the Company entered into transactions with Tauren and Langtry, both of which are entities controlled by Calvin Wallen III, the Chief Executive Officer of the Company, under which the Company acquired \$30,952,810 in pre-paid Drilling Credits applicable towards the development of its Haynesville Shale rights in Northwest Louisiana. The Company expects to use the Drilling Credits to fund \$30,952,810 of its share of the drilling and completion costs for those horizontal Haynesville Shale wells drilled in sections previously operated by an affiliate of the Company which are now operated by a third party. As of June 30, 2011, \$17,763,316 was the remaining balance of the Drilling Credits.

On May 18, 2011, EXCO and BG informed the Company that they do not intend to honor the balance of the Drilling Credits, which was approximately \$18 million at that time. The Company believes that there is no valid basis to dispute the remaining balance of the Drilling Credits. This dispute was submitted to mediation on August 26, 2011, but was not resolved. The Company has submitted this dispute to binding arbitration, and has filed a court action in District Court in Dallas County, Texas to compel such arbitration. The Company intends to continue to vigorously defend its rights to the remaining balance of the Drilling Credits. If the Company is not successful in defending its rights, it expects to fund its share of expenses from wells drilled by EXCO and BG through one of the other sources of funds described above.

Management believes we will prevail, but if not, we have the option of going "non-consent" or being deemed non-consent on current and future horizontal Haynesville Shale wells operated by EXCO and BG. By being deemed to be non-consent, in addition to penalties we would reduce our share of revenues from these wells, we would be required to pay the royalty owners their share of revenues, which we anticipate to be up to approximately \$65,000 per well per month, or an aggregate of approximately \$590,000 based on the current number of EXCO and BG operated wells for the balance of fiscal 2012. Other than this \$590,000, we do not expect any additional royalties to be paid out of pocket by Cubic during fiscal 2012, with respect to EXCO and BG operated wells. With future strategies to obtain additional financing, funds generated through existing wells and cash on hand, we expect to be able to continue to pay our expenses as they come due. It is possible that EXCO and BG exhaust the remaining balance of the Drilling Credits during fiscal 2012. The balance of the Drilling Credits not exhausted is due and payable in cash early in fiscal 2013.

Product prices, over which we have no control, have a significant impact on revenues from production and the value of such reserves and thereby on the Company's borrowing capacity, in the event the Company determines to borrow additional funds. Within the confines of product pricing, the Company needs to be able to find and develop or acquire oil and gas reserves in a cost effective manner in order to generate sufficient financial resources through internal means to complete the financing of its capital expenditure program.

During the twelve months ended June 30, 2011, the Company used cash flows from operating activities of \$2,567,159 as compared to \$681,713 in fiscal 2010. Cash flow from operations is dependent on our ability to increase production through our development and exploratory activities and the price received for oil and natural gas.

Working Capital and Cash Flow

The Company's working capital increased to \$2,319,621 at June 30, 2011 from (\$1,435,908) at June 30, 2010. This increase was primarily due to revenue increase of \$2,647,128, exercised warrants providing cash of \$642,700 and a \$5,000,000 increase to our revolving line of credit. The Amended Credit Agreement contains material covenants that include, but are not limited to, a right to Borrowing Base redeterminations, which can be made by Wells Fargo at any time. Any redetermination can reduce our revolving credit limit with any excess borrowings being due within 30 days or, at the Company's option, in five equal monthly installments. As of June 30, 2011, we are in full compliance with the Wells Fargo Credit Agreement.

Operating activities - During the twelve months ended June 30, 2011, the Company used cash flows from operating activities of \$2,567,159 as compared to \$681,713 in fiscal 2010 and \$2,152,187 in fiscal 2009. Cash flow from operations is dependent on our ability to increase production through our development and exploratory activities and the price received for oil and natural gas.

Investing activities - During the twelve months ended June 30, 2011, the Company used cash flows from investing activities of \$1,412,406 as compared to \$5,735,839 in fiscal 2010 and \$5,588,927 in fiscal 2009. Cash used in investing activities were for drilling and working interest participation during the three years to develop our assets.

Financing activities - During the twelve months ended June 30, 2011, the Company had cash flows from financing activities of \$5,129,915 as compared to \$6,738,400 in fiscal 2010 and \$5,668,152 in fiscal 2009. Cash provided by financing activities for fiscal periods 2011, 2010 and 2009 were from borrowings under the credit facility, borrowings from affiliates and issuances of stock. See the Note C-Stockholders' equity and Note E- Long-term debt for further discussion.

Capital Expenditures

The majority of our oil and gas reserves are undeveloped. As such, recovery of the Company's future undeveloped proved reserves will require significant capital expenditures. Management estimates that aggregate capital expenditures ranging from a minimum of approximately \$15,000,000 to a maximum of approximately \$20,000,000 will be made to further develop these reserves during fiscal 2012 (from currently available funds, Drilling Credits and projected cash from operating activities). Moreover, additional capital expenditures may be required for exploratory drilling on our undeveloped acreage. The Company may increase its planned activities for fiscal 2012, if product prices improve. The Company anticipates that its share of expenses with respect to the drilling and completion of these wells during fiscal 2012 will be approximately \$15 million, but the Company has little or no control with respect to the timing of EXCO drilling wells and the timing of drilling expenses incurred. Moreover, additional capital expenditures may be required for exploratory drilling on our undeveloped acreage. The Company may increase its planned activities for fiscal 2012 if product prices improve. If product prices remain flat or go lower such activities and our capital expenditures, may be restricted, although we have little or no control over expenditures incurred by our third-party operators.

The Company is considering acquiring leaseholds in additional properties, including properties that are expected to produce primarily oil. However, the Company cannot give any assurance that any such acquisition will be completed.

No assurance can be given that all or any of these anticipated or possible capital expenditures will be completed as currently anticipated. We believe that cash on hand, the remaining balance of the Drilling Credits and revenues from operations and availability under our revolving note will enable us to continue to meet our obligations and fund our projected capital expenditures for fiscal 2012. Any acquisition of additional leaseholds would require that we obtain additional capital resources.

Capital Resources

The Company plans to fund its development and exploratory activities through cash on hand, the Drilling Credits, cash provided from operations; and one of, or a combination of, the following potential transactions: a private placement of common stock; a public offering of common stock; a joint venture with an industry partner in which we would or could farm-out a to-be-determined percentage of our working interests in certain properties; a disposition of assets; or other transactions.

On May 18, 2011, EXCO and BG informed the Company that they do not intend to honor the balance of the Drilling Credits, which was approximately \$18 million at that time. The Company believes that there is no valid basis to dispute the remaining balance of the Drilling Credits. This dispute was submitted to mediation on August 26, 2011, but was not resolved. The Company has submitted this dispute to binding arbitration, and has filed a court action in District Court in Dallas County, Texas to compel such arbitration. The Company intends to continue to vigorously defend its rights to the remaining balance of the Drilling Credits. If the Company is not successful in defending its rights, it expects to fund its share of expenses from wells drilled by EXCO and BG through one of the other sources of funds described above.

Management believes we will prevail, but if not, we have the option of going “non-consent” or being deemed non-consent on current and future horizontal Haynesville Shale wells operated by EXCO and BG. By being deemed to be non-consent, in addition to penalties we would reduce our share of revenues from these wells, we would be required to pay the royalty owners their share of revenues, which we anticipate to be up to approximately \$65,000 per well per month, or an aggregate of approximately \$590,000 based on the current number of EXCO and BG operated wells for the balance of fiscal 2012. Other than this \$590,000, we do not expect any additional royalties to be paid out of pocket by Cubic during fiscal 2012, with respect to EXCO and BG operated wells. With future strategies to obtain additional financing, funds generated through existing wells and cash on hand, we expect to be able to continue to pay our expenses as they come due. It is possible that EXCO and BG exhaust the remaining balance of the Drilling Credits during fiscal 2012. The balance of the Drilling Credits not exhausted is due and payable in cash early in fiscal 2013.

We are negotiating with Wells Fargo to extend the maturity date of our Credit Agreement, which currently is July 1, 2012. There can be no assurance that the Company will be able to negotiate such extension.

We expect production from wells drilled and completed in fiscal 2009, 2010, 2011, together with additional wells that are expected to be completed during fiscal 2012, to provide cash flow to support additional drilling. However, the Company cannot be certain that adequate funds will be available from cash on hand, the Drilling Credits, operating cash flow, and the aforementioned potential transactions to fully fund the projected capital expenditures for fiscal 2012. Additionally, because future cash flows, the availability of borrowings, and the ability to consummate any of the aforementioned potential transactions are subject to a number of variables, such as prevailing prices of oil and gas, actual production from existing and newly-completed wells, the Company’s success in developing and producing new reserves, the uncertainty of financial markets and joint venture and merger and acquisition activity, and the uncertainty with respect to the amount of funds which may ultimately be required to finance the Company’s development and exploration program, there can be no assurance that the Company’s capital resources will be sufficient to sustain the Company’s development and exploratory activities.

If we are unable to obtain such capital resources on a timely basis, the Company may curtail its planned development and exploratory activities. If a well is proposed by a third-party operator and the Company does not have a drilling credit or the capital resources to participate in that well, the Company might not receive any revenue generated by that well, while still being required to fulfill the relevant royalty payment obligations to the mineral owner and other royalty holders. Additionally, because future cash flows and the availability of borrowings are subject to a number of variables, there can be no assurance that the Company’s capital resources will be sufficient to sustain the Company’s development and exploration activities.

Critical Accounting Policies

In response to the SEC's Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we have identified the most critical accounting policies used in the preparation of our consolidated financial statements. We determined the critical policies by considering accounting policies that involve our most complex or subjective decisions or assessments. We identified our most critical accounting policies to be those related to our proved reserves, accounts receivables, share-based payments, our choice of accounting method for oil and natural gas properties, goodwill, asset retirement obligations and income taxes.

We prepared our consolidated financial statements for inclusion in this report in accordance with GAAP. GAAP represents a comprehensive set of accounting and disclosure rules and requirements, and applying these rules and requirements requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. The following is a discussion of our most critical accounting policies, judgments and uncertainties that are inherent in our application of GAAP.

Estimates of Proved Reserves

The proved reserves data included in this Annual Report on Form 10-K was prepared in accordance with SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the technical qualifications, experience and judgment of the persons preparing the estimates.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate. The assumptions used for our Bossier/Haynesville, Cotton Valley and Hosston well and reservoir characteristics and performance are subject to further refinement as more production history is accumulated.

You should not assume that the present value of future net cash flows represents the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves according to the requirements in the SEC's Release No. 33-8995 "Modernization of Oil and Gas Reporting," or Release No. 33-8995. Actual future prices and costs may be materially higher or lower than the prices and costs used in the preparation of the estimate. Further, the mandated discount rate of 10% may not be an accurate assumption of future interest rates.

Proved reserves quantities directly and materially impact depletion expense. If the proved reserves decline, then the rate at which we record depletion expense increases, reducing net income. A decline in the estimate of proved reserves may result from lower market prices, making it uneconomical to drill or produce if the costs to drill or produce are expected to exceed such market prices. In addition, a decline in proved reserves may impact the outcome of our assessment of our oil and natural gas properties and require an impairment of the carrying value of our oil and natural gas properties.

Proved reserves are defined as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimates are deterministic estimates or probabilistic estimates. To be classified as proved reserves, the project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes both the area identified by drilling, but limited by fluid contacts, if any, and adjacent undrilled portions of the reservoir that can, with reasonable certainty, be

judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the deepest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish the deepest contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and the project has been approved for development by all necessary parties and entities, including governmental entities.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Accounting for oil and natural gas properties

The accounting for and disclosure of, oil and natural gas producing activities requires that we choose between two GAAP alternatives: the full cost method or the successful efforts method.

We use the full cost method of accounting, which involves capitalizing all acquisition, exploration, exploitation and development costs of oil and natural gas properties. Once we incur costs, they are recorded in the depletable pool of proved properties or in unproved properties, collectively, the full cost pool. Unproved property costs are not subject to depletion. We review our unproved oil and natural gas property costs on a quarterly basis to assess possible impairment or the need to transfer unproved costs to proved properties as a result of extension or discoveries from drilling operations. We expect these costs to be evaluated in one to seven years and transferred to the depletable portion of the full cost pool during that time. The full cost pool is comprised of intangible drilling costs, lease and well equipment and exploration and development costs incurred plus costs of acquired proved and unproved leaseholds.

During April 2004 we initiated leasing projects to acquire shale drilling rights in both the Johnson Branch and Bethany Longstreet fields in our Northeast Louisiana operating areas. In accordance with our policy and FASB ASC Subtopic 835-20 for Capitalization of Interest, we began capitalizing interest on unproved properties.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool and all estimated future development costs are divided by the total quantity of proved reserves. This rate is applied to our total production for the period, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs, including share-based compensation that is attributable to our acquisition, exploration, exploitation and development activities.

Under the full cost method of accounting, sales, dispositions and other oil and natural gas property retirements are generally accounted for as adjustments to the full cost pool, with no recognition of gain or loss unless the disposition would significantly alter the relationship between capitalized costs and proved reserves. Gain or loss recognition on divestiture or abandonment of oil and natural gas properties where

disposition would result in a significant alteration of the depletion rate requires allocation of a portion of the amortizable full cost pool based on the relative estimated fair value of the disposed oil and natural gas properties to the estimated fair value of total proved reserves. As discussed under “Estimates of Proved Reserves,” estimating oil and natural gas reserves involves numerous assumptions.

Prior to our December 31, 2009 adoption of Release No. 33-8995, at the end of each quarterly period the unamortized cost of oil and natural gas properties, net of related deferred income taxes, was limited to the full cost ceiling, computed as the sum of the estimated future net revenues from our proved reserves using period-end prices, discounted at 10%, and adjusted for related income tax effects (ceiling test). In the event our capitalized costs exceeded the ceiling limitation at the end of the reporting period, we subsequently evaluated the limitation for price changes occurring after the balance sheet date to assess impairment. Beginning December 31, 2009, Release No. 33-8995 requires that the full cost ceiling be computed as the sum of the estimated future net revenues from proved reserves using the average, first-day-of-the-month price during the previous 12-month period, discounted at 10% and adjusted for related income tax effects. The new rule no longer allows a company to subsequently evaluate the limitation for subsequent price changes. Under full cost accounting rules, any ceiling test write-downs of oil and natural gas properties may not be reversed in subsequent periods.

The quarterly calculation of the ceiling test is based upon estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

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 amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Certain significant estimates

Management’s estimates of oil and gas reserves are based on various assumptions, including constant oil and gas prices. It is reasonably possible that a future event in the near term could cause the estimates to change and such changes could have a severe impact. Actual future production, cash flows, taxes, operating expenses, development expenditures and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. While it is at least reasonably possible that the estimates above will change materially in the near term, no estimate can be made of the range of possible changes that might occur.

Asset retirement obligations

We follow FASB ASC Subtopic 410-20 for Asset Retirement Obligations to account for legal obligations associated with the retirement of long-lived assets. ASC 410-20 requires these obligations be recognized at their estimated fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The costs of plugging and abandoning oil and natural gas properties fluctuate with costs associated with the industry. We periodically assess the estimated costs of our asset retirement obligations and adjust the liability according to these estimates.

Accounting for income taxes

Income taxes are accounted for using the liability method of accounting in accordance FASB ASC Topic 740 for Income Taxes. We must make certain estimates related to the reversal of temporary differences, and

actual results could vary from those estimates. Deferred taxes are recorded to reflect the tax benefits and consequences of future years' differences between the tax basis of assets and liabilities and their financial reporting basis. We record a valuation allowance to reduce deferred tax assets if it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Stock-based compensation

We account for share-based payments to employees using the methodology prescribed in FASB ASC Topic 718 for Stock Compensation. ASC Topic 718 requires share-based compensation to be recorded with cost classifications consistent with cash compensation.

Subsequent Events

The FASB issued new authoritative guidance for subsequent events. Such authoritative guidance establishes general standards of accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. In particular, this statement sets forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. Adoption of this authoritative position did not have a material impact on the Company's condensed consolidated financial statements.

Other Accounting Policies and Recent Accounting Pronouncements

On January 21, 2010, the FASB issued Accounting Standards Update No. 2010-06—Fair Value Measurement and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements, or ASU 2010-06. ASU 2010-06 requires transfers, and the reasons for the transfers, between Levels 1 and 2 be disclosed, Level 3 reconciliations for fair value measurements using significant unobservable inputs should be presented on a gross basis, the fair value measurement disclosure should be reported for each class of asset and liability, and disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring will be required for fair value measurements that fall in either Level 2 or 3. The update is effective for interim and annual reporting periods beginning after December 15, 2009. This update currently will have no impact to our financial position.

On December 31, 2008, the SEC issued Release No. 33-8995, amending its oil and natural gas reporting requirements for oil and natural gas producing companies. On January 16, 2010, the FASB issued Update No. 2010-03—Extractive Activities—Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures, or Update No. 2010-03, to align the oil and gas reserve estimation and disclosure requirements of the Codification with Release No. 33-8995.

The effective date of the new accounting and disclosure requirements is for annual reports filed for fiscal years ending on or after December 31, 2009.

Among other things, Release No. 33-8995 and Update No. 2010-03:

- Revises a number of definitions relating to oil and natural gas reserves to make them consistent with the Petroleum Resource Management System, which includes certain non-traditional resources in proved reserves;
- Permits the use of new technologies for determining oil and natural gas reserves;
- Requires the use of the simple average spot prices for the trailing twelve month period using the first day of each month in the estimation of oil and natural gas reserve quantities and, for companies using the full cost method of accounting, in computing the ceiling limitation test, in place of a single day price as of the end of the fiscal year;
- Permits the disclosure in filings with the SEC of probable and possible reserves and sensitivity of our proved oil and natural gas reserves to changes in prices;
- Requires additional disclosures (outside of the financial statements) regarding the status of undeveloped reserves and changes in status of these from period to period; and

- Requires a discussion of the internal controls in place in the reserve estimation process and disclosure of the technical qualifications of the technical person having primary responsibility for preparing the reserve estimates.

Other Accounting Policies and Recent Accounting Pronouncements

Please see “Notes to Financial Statements – Note B – Significant accounting policies” elsewhere herein.

Inflation

Although the level of inflation affects certain of the Company’s costs and expenses, inflation did not have a significant effect on the Company’s results of operations during fiscal 2011.

Related Party Transactions

A description of our related party transactions is included in “Note F – Related party transactions” in the Notes to the Financial Statements of the Company included elsewhere in this Report, and is incorporated herein by reference.

Off-Balance Sheet Arrangements

We do not currently use any off-balance sheet arrangements to enhance our liquidity and capital resource positions, or for any other purpose.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Commodity Price Risk

We are subject to price fluctuations for natural gas, natural gas liquids and crude oil. Prices received for natural gas sold on the spot market are volatile due primarily to seasonality of demand and other factors beyond our control. Reductions in crude oil, natural gas and natural gas liquids prices could have a material adverse effect on our financial position, results of operations and quantities of reserves recoverable on an economic basis. Any reduction in reserves, including reductions due to price fluctuations, can adversely affect our liquidity and our ability to obtain capital for our acquisition and development activities. To date, we have not entered into futures contracts or other hedging agreements to manage the commodity price risk for a portion of our production.

Interest Rate Risk

As of June 30, 2011, we had \$37,000,000 of long-term debt outstanding under our Credit Facility, which matures on July 1, 2012, and the Wallen Note, which matures on September 30, 2012. This debt bears interest at the prime rate plus 2.0% for the Credit Facility and prime rate plus 1% for the Wallen Note. As a result, our interest costs fluctuate based on short-term interest rates. Based on the aforementioned borrowings outstanding at June 30, 2011, a 100 basis point change in interest rates would change our annual interest expense by approximately \$370,000. We had no interest rate derivatives during fiscal 2011.

Item 8. Financial Statements and Supplementary Data.

The Report of Independent Accountants, Financial Statements and any supplementary financial data required by this Item are set forth beginning on pages F-1, and are incorporated herein by reference.

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

None.

Item 9A. Controls and Procedures.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, as of the end of the period covered by this report. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosures.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an assessment, including testing, of the effectiveness of our internal control over financial reporting as of June 30, 2011 based on the criteria set forth in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

Based on our evaluation under the criteria set forth in *Internal Control—Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of June 30, 2011. This Annual Report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. We were not required to have, nor have we engaged our independent registered public accounting firm to perform, an audit on our internal control over financial reporting pursuant to the rules of the Securities and Exchange Commission that permit us to provide only management's report in this Annual Report.

Changes in Internal Control Over Financial Reporting

Subsequent to our evaluation, there were no changes in internal controls or other factors that could materially affect, or are reasonably likely to materially affect, these internal controls. We maintain a system of internal control over financial reporting. There were no changes in our internal control over financial reporting during the fourth quarter of fiscal 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations on Internal Control

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of

controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision making can be faulty, and that breakdowns can occur because of simple errors. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Certifications

Our chief executive officer and chief financial officer have completed the certifications required to be filed as an exhibit to this Report (see Exhibits 31.1 and 31.2) relating to the design of our disclosure controls and procedures and the design of our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Directors

The following table provides information concerning each of our directors as of September 9, 2011:

<u>Name</u>	<u>Age</u>	<u>Position(s) Held with Cubic</u>	<u>Director Since</u>
Calvin A. Wallen, III	56	Chairman of the Board, President and Chief Executive Officer	1997
Jon S. Ross	47	Corporate Secretary and Director	1998
Gene C. Howard	84	Director	1991
Bob L. Clements	68	Director	2004
Phyllis K. Harding	65	Director	2009
William L. Bruggeman, Jr.	84	Director	2009
David B. Brown	48	Director	2010
Paul R. Ferretti	64	Director	2010

CALVIN A. WALLEN, III has served as the President and Chief Executive Officer of the Company since December 1997, and as Chairman of the Board of Directors since June 1999. Mr. Wallen has over 30 years of experience in the oil and gas industry working as a drilling and petroleum engineer. Prior to joining Cubic, Mr. Wallen was employed by Superior Oil and various other drilling contractors including Resource, Tom Brown and Rowan International. Mr. Wallen assisted in the design and construction of several land rigs with advanced drilling systems and has domestic and international experience in drilling engineering. While employed by Rowan International, Mr. Wallen gained experience in drilling high angle directional wells at Prudhoe Bay on contract to Arco. In 1982, Mr. Wallen began acquiring and developing oil and gas properties, forming a production company that has evolved into Tauren Exploration, Inc. Mr. Wallen attended Texas A&M University at College Station, Texas.

JON S. ROSS has served as a director of the Company since April 1998 and as Secretary since November 1998. Since 1989, Mr. Ross has been a practicing attorney in Dallas, Texas representing over 80 business entities. He has served on several community and not-for-profit committees and boards and has been asked to speak to corporate and civic leaders on a variety of corporate law topics. Mr. Ross graduated from St. Mark's School of Texas with honors in 1982 and graduated from the University of Texas at Austin in 1986 with a B.B.A. in Accounting. He then graduated from the University of Texas School of Law in 1989 attaining a Juris Doctorate degree.

GENE C. HOWARD is the Senior Partner of the law firm of Howard, Widdows, and Bufogle, P.C. of Tulsa, Oklahoma and has been engaged primarily in the private practice of law over the past forty years. Mr. Howard served in the Oklahoma State Senate from 1964 through 1982 and was President Pro Tem from 1975 through 1981. In addition, he served as the Chairman of the Board of Farmers and Exchange Bank from 1972 through 1991 and on the Board of Directors of Local Federal Bank of Oklahoma. Mr. Howard is a Director of the Oklahoma State Education and Employment Group Insurance Board and presently acts as Chairman. Mr. Howard served as Director of EntreCap Financial Corporation and Hinderliter Construction, Inc. from 1991 to August 1992.

BOB L. CLEMENTS joined the Company's board of directors in February 2004. Mr. Clements has a degree in the OPM Program from the Harvard Business School. Mr. Clements has been in the wholesale food and restaurant business for over thirty years, currently controlling the largest independent producer of stuffed jalapenos and corn dogs as well as two successful restaurants in the Rockwall, Texas area. Mr. Clements has served and currently serves on a variety of for-profit and not-for-profit committees and boards.

PHYLLIS K. HARDING has worked as an executive advisor for Diversified Dynamics Corporation, a privately held corporation controlled by William L. Bruggeman, Jr., since 1990. From 2001 through 2008 she served on the Board of Directors of Dayport Inc., a leader in video publishing, content, workflow and syndication solutions. Dayport Inc. was acquired by Entrig Inc. in 2008. From 2001 to the present time she has served on the Board of Advisors of Geospan Corporation and Geospan.com, privately held industry leaders in spatial imaging and visual mapping solutions. She has worked with numerous businesses in various industries as the head of the consulting division for Grant Thornton LLP in Minneapolis from 1987 through 1988 and as a co-owner of Camelot Consultants, Inc. from 1989 through 1999. Ms. Harding has three decades of operational, manufacturing; turn-around and strategic leadership experience with various clients and direct employment at The Valspar Corporation (1986 through 1987) and Procter and Gamble (1975 through 1986). She is a graduate of the University of Wisconsin – Green Bay.

WILLIAM L. BRUGGEMAN, JR. is the founder and controlling stockholder of Diversified Dynamics Corporation (founded in 1968) and its business divisions: Cat Pumps, a manufacturer of quality, industrial, positive displacement, triplex piston and plunger pumps and custom engineered pumping systems with over 40 years of experience in industrial high pressure systems; and HomeRight, a manufacturer of home improvement products. He is an entrepreneur and "angel investor" who has been involved in many successful start-up businesses. He has been a significant investor in the oil and gas industries since the early 1990s. He continues to be a major stockholder of Cubic Energy, Inc. Mr. Bruggeman's former employers includes McCullough Corporation, John Deere, L & A Products, and Minneapolis Moline. Mr. Bruggeman is a veteran who served thirty months in the U.S. Navy and one year in the U.S. Marine Corps. Mr. Bruggeman graduated from Hamline University with a degree in Engineering.

DAVID B. BROWN has served as the Chief Financial Officer for Dresser, Inc., a \$2 billion multi-national energy equipment company that serves the upstream, midstream and downstream oil, gas and power markets, since 2011. He was Chief Accounting Officer and Controller for Dresser, Inc. from 2007 to 2010. From 2003 until 2007, Mr. Brown served various roles including divisional Vice President, Controller and Chief Audit Executive for the Brink's Company, a global security services company with operations in more than 130 countries. Prior to joining Brinks, Mr. Brown spent 8 years with LSG Sky Chefs, a \$3 billion airline catering company owned by Lufthansa, in leadership roles with progressive responsibility including three years in Sao Paulo Brazil as Vice President Finance, Latin America. Prior to that time, Mr. Brown spent 10 years with Price Waterhouse, where he advised multi-national clients primarily in the energy industry, while living in Moscow, London and the United States. He has also served in a variety of board of director capacities for

several Dallas-based arts and humanities nonprofit organizations and is an active member of the Dallas Committee for Foreign Relations, the World Affairs Council and the Boy Scouts of America. Mr. Brown has a Bachelor of Business Administration degree in Accounting from The University of Texas – Austin and is a Certified Public Accountant.

PAUL R. FERRETTI served as Managing Director – Head of Energy Investment Banking with Wunderlich Securities Inc., an investment banking firm, from 2008 through 2010. From 2005 until joining Wunderlich Securities, Mr. Ferretti served as Senior Vice President – Head of Energy Investment Banking at Ferris, Baker, Watts Inc., an investment banking firm. At Ferris, Baker, Watts, Mr. Ferretti established and lead a comprehensive energy team, including both equity research and investment banking. Mr. Ferretti ran the energy investment banking practice at Ferris, Baker, Watts. From 2004 until joining Ferris, Baker, Watts, Mr. Ferretti served as Managing Director of Ladenburg Thalmann & Company, an investment banking firm. Prior to 2004, Mr. Ferretti served with various companies as Sr. Vice President and as Senior Equity Analyst. During his equity research career, Mr. Ferretti was a member of the New York Society of Security Analysts. Mr. Ferretti was recently elected to the Board of Directors of NGAS Resources, Inc., an independent exploration and production company. Mr. Ferretti holds a Bachelor of Science degree in Economics from Brooklyn College and served in the United States Army, which included a one year tour of duty in Vietnam.

There are no family relationships among any of the directors or executive officers of the Company. See “Certain Relationships and Related Transactions” for a description of transactions between the Company and its directors, executive officers or their affiliates.

Executive Officers

<u>Name</u>	<u>Age</u>	<u>Position(s) Held with Cubic</u>	<u>Since</u>
Calvin A. Wallen, III*	56	Chairman of the Board, President and Chief Executive Officer	1997
Larry G. Badgley	54	Chief Financial Officer	2008
Jon S. Ross*	47	Corporate Secretary and Director	1998

See Mr. Wallen’s and Mr. Ross’s biographies above.

LARRY G. BADGLEY joined the Company in August 2008, as a consultant, and was appointed Chief Financial Officer in October 2008. Prior to joining the Company, from October 2005 through September 2006, Mr. Badgley served as Managing Director of BridgePoint Consulting, a provider of CFO services to venture capital-backed and early stage companies. In that capacity, Mr. Badgley was primarily responsible for strategic planning for growth companies. From July 1998 through October 2005, Mr. Badgley served as Director of Accounting and Finance for Jefferson Wells International, an international professional services firm. Prior to that time, Mr. Badgley served as Chief Operating Officer and Chief Financial Officer of a privately held national sign manufacturer until its sale in July 1998. Mr. Badgley received a BBA in Finance from Hardin-Simmons University and is a Certified Public Accountant.

Audit Committee; Financial Expert

The Audit Committee is comprised of Messrs. Brown (Chairman), Howard and Clements. All of the members of the Audit Committee are “independent” under the rules of the SEC and the NYSE-Amex, LLC. The Board of Directors, after reviewing all of the relevant facts, circumstances and attributes, has determined that Messrs. Howard and Brown satisfy the requirements of an “audit committee financial expert” on the Audit Committee as that term is defined in Item 407(d)(5)(ii) of Regulation S-K promulgated under the Exchange Act by the SEC.

Compliance with Section 16(a) of the Exchange Act

Section 16(a) of the Exchange Act requires the Company's directors, executive officers, and holders of more than 10% of the common stock to file with the SEC reports of ownership and changes in ownership of common stock. SEC regulations require those directors, executive officers, and greater than 10% stockholders to furnish the Company with copies of all Section 16(a) forms they file. Based on the Company's review of reports, the Company believes that Messrs. Brown, Bruggeman, Clements, Ferretti, Howard and Wallen and Ms. Harding each made one late filing reporting one transaction. Hebert A. Bayer, a director during fiscal 2011, made six late filings reporting an aggregate of ten late transactions.

Director Independence

Our Board currently has two members from management, Calvin A. Wallen, III, our Chairman, President and Chief Executive Officer and Jon S. Ross, the Secretary, and six non-management directors, Gene C. Howard, Bob L. Clements, William L. Bruggeman Jr., Phyllis K. Harding, David B. Brown and Paul R. Ferretti. The Board has determined that each of its non-management members meets the criteria for independence under AMEX listing standards. Because of their management roles, Mr. Wallen and Mr. Ross are not considered independent directors and do not sit on any committees of the Board.

CODE OF BUSINESS CONDUCT AND ETHICS

The Company has adopted a Code of Business Conduct and Ethics that applies to its directors, officers and employees. A copy of the Code of Business Conduct and Ethics is available in the "Governance" section on the Company's website at www.CubicEnergyInc.com.

Item 11. Executive Compensation.

Compensation Discussion and Analysis

General. Our Board of Directors has established a Compensation Committee, comprised entirely of independent non-employee directors, with authority to set all forms of compensation of our executive officers. Messrs. Brown, Bruggeman, Ferretti and Ms. Harding comprise the Compensation Committee, currently. The Compensation Committee has overall responsibility for our executive compensation policies as provided in a written charter adopted by the Board of Directors. The Compensation Committee is empowered to review and approve the annual compensation and compensation procedures for our executives: the President and Chief Executive Officer, the Chief Financial Officer, and the Secretary. The Compensation Committee does not delegate any of its functions to others in setting compensation.

When establishing base salaries, cash bonuses and equity grants for each of the executives, the Compensation Committee considers the recommendations of the President and Chief Executive Officer and the Secretary, the executive's role and contribution to the management team, responsibilities and performance during the past year and future anticipated contributions, corporate performance, and the amount of total compensation paid to executives in similar positions, and performing similar functions, at other companies for which data was available, as provided by third party compensation studies. One such study, published in September 2009 by Salary.com was a blind survey of over 1,000 companies located in the Dallas metropolitan area in the "Energy & Utilities" industry with less than 25 full-time equivalent employees. Another study, published in December 2008, included data from a survey of the following comparable companies: Abraxas Petroleum Corporation, Arena Resources, Inc., ATP Oil & Gas, Berry Petroleum Company, Canadian Superior Energy, Edge Petroleum and Goodrich Petroleum Corporation.

In addition, during fiscal 2011, a study was done of the compensation practices of GMX Resources, Inc. (approximately twice the market cap of the Company at the time of the study) and of NGAS Resources, Inc. (approximately one-half the market cap of the Company at the time of the study). These studies were used to corroborate the compensation levels for each of the officers; and the studies were used to help determine the compensation included in the employment agreement with Larry G. Badgley, which was entered into on January 13, 2011 and effective as of October 1, 2010.

The Compensation Committee relies upon its judgment in making compensation decisions, after reviewing the Company's performance and evaluating each executive's performance during the year. The Committee generally does not adhere to formulas or necessarily react to short-term changes in business performance in determining the amount and mix of compensation elements. We incorporate flexibility into our compensation programs and in the assessment process to respond to and adjust for the evolving business environment.

Compensation Philosophy. The Compensation Committee's compensation philosophy is to reward executive officers for the achievement of short and long-term corporate objectives and for individual performance. The objective of this philosophy is to provide a balance between short-term goals and long-term priorities to achieve immediate objectives while also focusing on increasing stockholder value over the long term. Also, to ensure that we are strategically and competitively positioned for the future, the Compensation Committee has the discretion to attribute significant weight to other factors in determining executive compensation, such as maintaining competitiveness, pursuing growth opportunities and achieving other long-range business and operating objectives. The level of compensation should also allow us to attract, motivate, and retain talented executive officers who contribute to our long-term success. The compensation of our President and Chief Executive Officer and other executive officers is comprised of cash compensation and long-term incentive compensation in the form of base salary, discretionary bonuses and stock awards.

Executive Compensation Components. Our total compensation for the named executive officers consisted of:

- base salary,
- bonuses and
- long-term equity incentives.

The Compensation Committee believes that each of these components is necessary to achieve Cubic's objective of retaining highly qualified executives and motivating the named executive officers to maximize stockholder return.

In setting fiscal 2011 compensation, the Compensation Committee considered the specific factors discussed below:

Base Salary. In setting the executive officers' base salaries, the Compensation Committee considers the achievement of corporate objectives as well as individual performance. Because the Compensation Committee believes that executive compensation should be viewed in terms of a balanced combination of cash compensation (i.e., base salaries and bonuses) and long-term incentive (i.e., grants of stock), base salaries are targeted to approximate the low end of the range of base salaries paid to executives of similar companies for each position. To ensure that each executive is paid appropriately, the Compensation Committee considers the executive's level of responsibility, prior experience, overall knowledge, contribution to business results, existing equity holdings, executive pay for similar positions in other companies, and executive pay within our company.

The base salaries paid to our named executive officers during fiscal 2011 are set forth below in the Summary Compensation Table. There were no increases in executive officers base salaries during fiscal 2011, except for Mr. Badgley's base salary went up from \$145,000 to \$163,800 per the employment agreement effective October 1, 2010.

Discretionary Bonuses. Executive bonuses are intended to link executive compensation with the attainment of Company goals. The actual payment of bonuses is primarily dependent upon the extent to which these Company-wide objectives are achieved. Determination of executive bonus amounts is not made in accordance with a strict formula, but rather is based on objective data combined with competitive ranges and internal policies and practices, including an overall review of both individual and corporate performance. No bonuses were paid to our named executive officers during fiscal 2011 or 2010. For fiscal 2009, bonuses to executives were primarily based upon the achievement of certain business objectives including progress in meeting our expected drilling and completion schedule, and obtaining additional financing. The President

and Chief Executive Officer has the discretion to recommend to the Compensation Committee to increase or decrease bonuses for all other executive officers, but any bonus amounts must be approved by the Compensation Committee.

Long-Term Incentives. On December 29, 2005, the stockholders of the Company approved the 2005 Stock Option Plan (the "Plan") under which our executive officers may be, among other forms of compensation, compensated through grants of shares of our common stock and/or grants of options to purchase shares of common stock. The Compensation Committee approves Plan grants that provide additional incentives and align the executives' long-term interests with those of the stockholders of the Company by tying executive compensation to the long-term performance of the Company's stock price. Annual equity grants for our executives are typically approved in January.

<u>Name and Principal Position</u>	<u>Fiscal Year</u>	<u>Percentage of Total Compensation</u>				<u>All Other Compen- sation</u>	<u>Total</u>
		<u>Salary</u>	<u>Bonus</u>	<u>Option Awards</u>			
Calvin A. Wallen, III Chairman of the Board, President and Chief Executive Officer	2011	97.1%	0.0%	0.0%	2.9%	100.0%	
	2010	97.7%	0.0%	0.0%	2.3%	100.0%	
	2009	98.2%	0.0%	0.0%	1.8%	100.0%	
Larry G. Badgley Chief Financial Officer	2011	59.8%	0.0%	37.9%	2.3%	100.0%	
	2010	96.8%	0.0%	0.0%	3.2%	100.0%	
	2009	96.8%	0.7%	0.0%	2.5%	100.0%	
Jon S. Ross Secretary and Director	2011	96.2%	0.0%	0.0%	3.8%	100.0%	
	2010	96.9%	0.0%	0.0%	3.1%	100.0%	
	2009	96.0%	1.7%	0.0%	2.3%	100.0%	

The Compensation Committee recommends equity to be granted to an executive with respect to shares of common stock based on the following principal elements including, but not limited to:

- President and Chief Executive Officer's and Secretary's recommendations;
- Management role and contribution to the management team;
- Job responsibilities and past performance;
- Future anticipated contributions;
- Corporate performance; and
- Existing equity holdings.

Determination of equity grant amounts is not made in accordance with a formula, but rather is based on objective data combined with competitive ranges, past internal policies and practices and an overall review of both individual and corporate performance. Equity grants may also be made to new executives upon commencement of employment and, on occasion, to executives in connection with a significant change in job responsibility. The Compensation Committee believes annual equity grants more closely align the long-term interests of executives with those of stockholders and assist in the retention of key executives. As such, these grants comprise the Company's principal long-term incentive to executives.

Other Compensation Policies Affecting the Executive Officers

Stock Ownership Requirements. The Compensation Committee does not maintain a policy relating to stock ownership guidelines or requirements for our executive officers because the Compensation Committee does not feel that it is necessary to impose such a policy on our executive officers. If circumstances change, the Compensation Committee will review whether such a policy is appropriate for executive officers.

Employment Agreements. On February 29, 2008, the Company entered into employment agreements with its President and Chief Executive Officer, Calvin A. Wallen, III, and Secretary, Jon S. Ross. The agreement with Mr. Wallen provides for a base salary of \$200,000 per year, while the agreement with Mr. Ross provides for a base salary of \$150,000 per year. The other terms and conditions of the agreements are substantially consistent.

Both agreements provide for a term of employment of 36 months from the effective date of February 1, 2008, which term shall be automatically extended by one additional month upon the expiration of each month during the term; provided, that the Company may terminate subsequent one-month extensions at any time. Each agreement is subject to early termination by the Company in the event that the employee dies, becomes totally disabled or commits an act constituting "Just Cause" under the agreement. The agreements provide that Just Cause includes, among other things, the conviction of certain crimes, habitual neglect of his duties to the Company or other material breaches by the employee of the agreement. Each agreement also provides that the employee shall be permitted to terminate his employment upon the occurrence of "Good Reason," as defined in the agreement. The agreements provide that Good Reason includes, among other things, a material diminution in the employee's authority, duties, responsibilities or salary, or the relocation of the Company's principal offices by more than 50 miles. If the employee's employment is terminated by (a) the Company other than due to the employee's death, disability or Just Cause, or (b) the employee for Good Reason, then the Company is required to pay all remaining salary through the end of the then-current term. The foregoing severance payment is subject to reduction under certain conditions.

On January 14, 2011, the Company entered into an employment agreement with its Chief Financial Officer, Larry G. Badgley. The agreement provides for a base salary of \$163,800, on an annual basis, and a term of employment of twenty-four (24) months from the effective date of October 1, 2010. The agreement also provides for the grant of stock options for the purchase of an aggregate of 288,667 shares of Company common stock. The agreement is subject to early termination by the Company in the event that Mr. Badgley dies, becomes totally disabled or commits an act constituting "Just Cause," as defined under the agreement, or upon a change in control of the Company. The agreement provides that Just Cause includes, among other things, the conviction of certain crimes, repeated neglect of his duties to the Company or other material breaches by Mr. Badgley of the agreement. The agreement also provides that Mr. Badgley shall be permitted to terminate his employment upon the occurrence of "Good Reason," as defined in the agreement. The agreement provides that Good Reason includes, among other things, a material diminution in Mr. Badgley's authority, duties, responsibilities or salary, or the relocation of the Company's principal executive offices by more than 50 miles. If Mr. Badgley's employment is terminated prior to the end of the term by (a) the Company, other than due to Mr. Badgley's death, disability or Just Cause, or upon a change in control or (b) Mr. Badgley for Good Reason, then the Company is required to pay all remaining salary through the end of the term.

The following table sets forth the estimated amounts that would be payable to each of the named executives upon a termination under the scenarios outlined above, excluding termination for Just Cause or on account of death or disability, assuming that such termination occurred on June 30, 2011. There can be no assurance that these scenarios would produce the same or similar results as those disclosed if a termination occurs in the future.

<u>Without Just Cause/ For Good Reason</u>		<u>Severance Payment</u>	<u>Total</u>
Calvin A. Wallen, III	(1)	\$ 600,000	\$ 600,000
Jon S. Ross	(1)	\$ 450,000	\$ 450,000
Larry G. Badgley	(2)	\$ 204,750	\$ 204,750

(1) Represents 36 months of base salary.

(2) Represents 15 months of base salary .

Tax Considerations

Compliance with Section 162(m) of the Internal Revenue Code. Section 162(m) disallows a federal income tax deduction to publicly held companies for certain compensation paid to our Named Executive Officers to the extent that compensation exceeds \$1 million per executive officer covered by Section 162(m) in any fiscal year. The limitation applies only to compensation that is not considered “performance based” as defined in the Section 162(m) rules. In designing our compensation programs, the Compensation Committee considers the effect of Section 162(m) together with other factors relevant to our business needs. We have historically taken, and intend to continue taking, appropriate actions, to the extent we believe desirable, to preserve the deductibility of annual incentive and long-term performance awards. However, the Compensation Committee has not adopted a policy that all compensation paid must be tax-deductible and qualified under Section 162(m). We believe that the fiscal 2011 base salary, annual bonus and stock grants paid to the individual executive officers covered by Section 162(m) did not exceed the Section 162(m) limit and will be fully deductible under Section 162(m).

Chief Executive Officer Compensation

Mr. Wallen received \$200,000 in base salary for fiscal 2011. His annual base salary was not increased for fiscal year 2011. Mr. Wallen received no common stock awards during fiscal 2011.

Chief Financial Officer Compensation

Mr. Badgley's salary was previously established at \$145,000 per year, plus a \$300 per month health insurance subsidy. In February 2010, the health insurance subsidy was increased to \$500 per month. On January 14, 2011, the Company entered into an employment agreement with Mr. Badgley. The agreement provides for a base salary of \$163,800, on an annual basis, and a term of employment of twenty-four (24) months from the effective date of October 1, 2010. The agreement also provides for the grant of options for the purchase of an aggregate of 288,667 shares of Company common stock.

Summary Compensation Table

The following table shows information regarding the compensation earned during the fiscal years ended June 30, 2011, 2010 and 2009 by our Chief Executive Officer, our Chief Financial Officer, and our other most highly compensated executive officer who was employed by us as of June 30, 2011 and whose total compensation exceeded \$100,000 during the most recent fiscal year (the “Named Executive Officers”):

<u>Name and Principal Position</u>	<u>Fiscal Year</u>	<u>Salary</u>	<u>Bonus</u>	<u>Option Awards</u>	<u>All Other Compen- sation (1)</u>	<u>Total</u>
Calvin A. Wallen, III Chairman of the Board, President and Chief Executive Officer	2011	\$ 200,000	\$ -	\$ -	\$ 6,000	\$ 206,000
	2010	\$ 200,000	\$ -	\$ -	\$ 4,800	\$ 204,800
	2009	\$ 200,000	\$ -	\$ -	\$ 3,600	\$ 203,600
Larry G. Badgley Chief Financial Officer	(2) 2011	\$ 159,100	\$ -	\$ 100,997	\$ 6,000	\$ 266,097
	2010	\$ 145,000	\$ -	\$ -	\$ 4,800	\$ 149,800
	2009	\$ 103,293	\$ 750	\$ -	\$ 2,700	\$ 106,743
Jon S. Ross Secretary and Director	2011	\$ 150,000	\$ -	\$ -	\$ 6,000	\$ 156,000
	2010	\$ 150,000	\$ -	\$ -	\$ 4,800	\$ 154,800
	2009	\$ 150,000	\$ 2,625	\$ -	\$ 3,600	\$ 156,225

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- (1) All Other Compensation consists solely of a \$500 per month (increased in February 2010 from \$300) reimbursement towards each officer's medical insurance premiums. The Company does not provide group health insurance coverage to its employees.
- (2) On January 14, 2011, Mr. Badgley received a grant of options for the purchase of an aggregate of 288,667 shares, exercisable at \$1.20 per share of Company common stock.

Fiscal 2011 Grants of Plan-Based Awards

Stock options were granted to Mr. Badgley during fiscal 2011.

On January 14, 2011, the Company entered into an employment agreement with its Chief Financial Officer, Larry G. Badgley. The agreement provides for the grant of stock options, under the Plan, for the purchase of an aggregate of 288,667 shares of Company common stock. These options have an exercise price \$1.20 per share and expire five years from their issue date. One option, for the purchase of 15,667 shares, was fully vested upon grant. The other option, for the purchase of 273,000 shares shall, subject to the other provisions of the option agreement, vest upon the earliest of: (a) immediately prior to a Change in Control (as defined in the Plan), (b) October 1, 2012, provided that Mr. Badgley's Continuous Service (as defined in the Plan) continues through October 1, 2012, (c) the termination by Mr. Badgley of his Continuous Service prior to October 1, 2012 in compliance with the terms of a then-effective written employment agreement between him and the Company or an affiliate of the Company or (d) the termination by the Company of Mr. Badgley's Continuous Service prior to October 1, 2012, other than for Just Cause (as defined in the employment agreement). We estimated the fair value of the options on the date of grant using the Black-Scholes valuation model to be \$100,997. We recorded \$31,531 of compensation expense for the year ended June 30, 2011 and estimate that approximately \$13,025 will be recognized quarterly until the options are fully vested on October 1, 2012.

The weighted-average fair value at the grant date using the Black-Scholes valuation model for options issued during fiscal 2011 was \$0.35 per share. The fair value of options at the date of grant was estimated using the following weighted-average assumptions for fiscal 2011: (a) no dividend yield on our common stock, (b) expected stock price volatility of 73%, (c) a discount rate of 2.04% and (d) an expected option term of 5 years.

The expected term of the options represents the estimated period of time until exercise and is based on consideration to the contractual terms, vesting schedules and expectations of future employee behavior. For fiscal 2011, expected stock price volatility is based on the historical volatility of our common stock.

The risk-free interest rate is based on the U.S. Treasury bill rate in effect at the time of grant with an equivalent expected term or life.

Information regarding activity for stock options under the Plan is as follows:

	Number of shares	Weighted- average exercise price per share	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Outstanding, June 30, 2010	-	\$ -		
Options granted	288,667	1.20		
Options exercised	-	-		
Options forfeited/expired	-	-		
Outstanding, June 30, 2011	288,667	1.20	4.5	-
Exercisable, June 30, 2011	15,667	1.20	4.5	-

Information related to the Plan during fiscal June 30, 2011 is as follows:

Intrinsic value of options exercised	\$	-
Weighted-average fair value of options granted	\$	100,997

Stock Grants

On January 12, 2009, the Company issued 235,000 shares to three directors of the Company pursuant to the Plan. As of such date, the aggregate market value of the common stock granted was \$385,400 based on the last sale price (\$1.64 per share) on the aforementioned date, on the AMEX, of the Company's common stock. Such amounts were expensed upon issuance to compensation expense.

On February 3, 2010, the Company issued 370,014 shares to five non-employee directors of the Company pursuant to the Plan. As of such date, the aggregate market value of the common stock granted was \$395,915 based on the last sale price (\$1.07 per share) on the aforementioned date, on the AMEX of the Company's common stock. Such amounts were recorded as compensation expense upon issuance.

On November 30, 2010, the Board of Directors increased the number of directors of the Company and appointed David B. Brown and Paul R. Ferretti to fill the vacancies created by such increase, in accordance with the provisions of the Company's bylaws. The Board authorized stock grants of 3,507 to each of Messrs. Brown and Ferretti, which number of shares is equal to the number of shares granted to other non-management directors for calendar year 2010, on a pro-rated basis, with an aggregate market value of the common stock granted was \$4,418 based on at the last sale price (\$0.63 per share) on the aforementioned date, on the AMEX of the Company's common stock. Such amounts were recorded as compensation expense upon issuance.

On January 17, 2011, the Company issued 460,000 unregistered shares of common stock to seven directors of the Company pursuant to the Plan. As of such date, the aggregate market value of the common stock granted was \$538,200 based on the last sale price (\$1.17 per share) on January 11, 2011, on the AMEX of the Company's common stock. Such amount was expensed upon issuance to compensation expense.

Outstanding Equity Awards at Fiscal Year-End

The following table set forth certain information, as of June 30, 2011, regarding stock option grants by the Company:

Name	Number of Securities underlying unexercised options exercisable	Number of Securities underlying unexercised options unexercisable	Option exercise price	Option expiration date
Larry G. Badgley	15,667	273,000	\$1.20	October 1, 2015

Option Exercises and Stock Vesting

No stock options were exercised or stock grants vested at any time during fiscal 2011.

Information Related to Stock-Based Compensation

The Company accounts for its stock-based employee compensation plans pursuant to FASB ASC Topic 718-Stock Compensation. ASC Topic 718 requires all share-based payments to employees, including grants of employee stock options, to be recognized in our consolidated statements of operations based on their estimated fair values. We recognize expense on a straight-line basis over the vesting period of the option.

Pension Benefits and Non-Qualified Defined Contribution Plans

The Company does not sponsor any qualified or non-qualified defined benefit plans or non-qualified defined contribution plans. The Compensation Committee, which is comprised solely of “outside directors” as defined for purposes of Section 162(m) of the Code, may elect to adopt qualified or non-qualified defined benefit or non-qualified contribution plans if the Compensation Committee determines that doing so is in our best interests.

Non-Employee Director Compensation for Fiscal 2011

Our philosophy in determining director compensation is to align compensation with the long-term interests of the stockholders, adequately compensate the directors for their time and effort, and establish an overall compensation package that will attract and retain qualified directors. In determining overall director compensation, we seek to strike the right balance between the cash and stock components of director compensation. The Board’s policy is that the directors should hold equity ownership in the Company and that a portion of the director fees should consist of Company equity in the form of stock grants.

Our retainer changed slightly during fiscal 2011 versus 2010 and 2009, but our meeting fee schedule remained the same for fiscal 2011 as it was in 2010 and 2009. Each non-employee director of the Company received cash compensation as follows:

- A meeting fee of \$1,000 [not to exceed \$1,000 in any one day, beginning with the January 11, 2011 Board meeting] for each board or committee meeting attended (whether in person or via teleconference);
- Each non-employee director as of January 2011 received: 40,000 shares of common stock for service on the Board of Directors; 20,000 shares of common stock for service on the Audit Committee; and, 10,000 shares of common stock for service on the Compensation Committee and/or the Nominating Committee. Mr. Brown received an additional 10,000 shares of common stock for serving as the financial expert and Chairman of the Audit Committee.

The following table sets forth the cash and other compensation paid to the non-employee members of our Board of Directors in fiscal 2011.

Name	Fees Earned or Paid in Cash (\$)	Stock Awards (\$) (1)	Total (\$)
Gene C. Howard	\$20,000	\$81,900	\$101,900
Herbert A. Bayer	17,000	70,200	87,200
Bob L. Clements	20,000	81,900	101,900
Phyllis K. Harding	12,000	70,200	82,200
William L. Bruggeman, Jr.	12,000	70,200	82,200
David B. Brown (2)	13,000	95,809	108,809
Paul J. Ferretti (2)	9,000	72,409	81,409
Totals	\$103,000	\$542,618	\$645,618

(1) *The market value of these stock awards is based on the closing price on the grant date, which was \$1.17 on January 11, 2011.*

(2) *Messrs. Brown and Ferretti received prorated common stock awards of 3,507 shares, the market value of which is based on the closing price on the grant date, which was \$0.63 on November 30, 2010.*

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The following table sets forth the number of shares of the Company's common stock beneficially owned, as of September 9, 2011 by (i) each person known to the Company to beneficially own more than 5% of the common stock of the Company (the only class of voting securities now outstanding), (ii) each director and Named Executive Officer, and (iii) all directors and executive officers as a group. Unless otherwise indicated, we consider all shares of common stock that can be issued under convertible securities or warrants currently or within 60 days of September 9, 2011 to be outstanding for the purpose of computing the percentage ownership of the person holding those securities, but do not consider those securities to be outstanding for computing the percentage ownership of any other person. Each owner's percentage is calculated by dividing the number of shares beneficially held by that owner by the sum of 76,815,908, plus the number of shares that owner has the right to acquire within 60 days.

<u>Name and Address</u>	<u>Number of Shares</u>	<u>Approximate Percent of Class (1)</u>
5% Stockholders		
Wells Fargo Energy Capital, Inc. 1000 Louisiana 9th Floor, Houston, TX 77002	13,544,900 (2)	13.6%
Steven S. Bruggeman 5609 St. Albans Circle, Shoreview, MN 55126	3,930,495 (3)	4.5%
Named Executive Officers and Directors		
Calvin A. Wallen, III 9870 Plano Road, Dallas, TX 75238	27,623,131 (4)	32.2%
William L. Bruggeman, Jr. 20 Anemone Circle, North Oaks, MN 55127	17,793,978 (5)	20.7%
Bob L. Clements 9870 Plano Road, Dallas, TX 75238	1,112,527 (6)	1.3%
Phyllis K. Harding 1681 94th Lane N.E., Minneapolis, MN 55449	893,970 (7)	1.0%
Gene C. Howard 2402 East 29th St., Tulsa, OK 74114	870,180 (8)	1.0%
Jon S. Ross 9870 Plano Road, Dallas, TX 75238	433,000 (9)	*
Paul R. Ferretti 8 Edgewood Road, Yardley, PA 19067	63,507	*
David B. Brown 4823 Ellensburg Drive, Dallas, TX 75244	83,507	*
Larry G. Badgley 9870 Plano Road, Dallas, TX 75238	15,667 (10)	*
All officers and directors as a group (9 persons)	48,889,467	56.9%

* Denotes less than one percent

(1) Based on a total of 76,815,908 shares of common stock issued and outstanding on September 9, 2011.

(2) Includes warrants to purchase 8,500,000 shares and a promissory note convertible into 5,044,900 shares.

- (3) Includes 831,745 shares held jointly by Steven S. Bruggeman and his spouse as joint tenants with rights of survivorship; 65,250 shares held by Mr. Bruggeman's spouse, of which Mr. Bruggeman disclaims beneficial ownership and, 2,033,500 shares and warrants to purchase 1,000,000 shares individually held by Steven S. Bruggeman.
- (4) Includes 10,350,000 shares plus 9,093,583 shares issuable upon conversion of preferred shares held by Langtry Mineral and Development, LLC, an entity controlled by Mr. Wallen; 700,000 shares held by Tauren Exploration, Inc., an entity controlled by Mr. Wallen; 500,000 shares held by Mr. Wallen's spouse; 386,000 shares held by minor children; and 6,593,548 held by Mr. Wallen.
- (5) Includes 2,034,000 shares and warrants to purchase 600,000 shares held by Diversified Dynamics Corporation, a company controlled by William Bruggeman; 40,000 shares owned by Mr. Bruggeman; 120,000 shares owned by Consumer Products Corp., in which Mr. Bruggeman's spouse is a joint owner; and, 14,999,978 shares owned by Mr. and Mrs. Bruggeman, as joint tenants with rights of survivorship.
- (6) Includes 109,527 shares held with Mr. Clements' spouse as joint tenants with rights of survivorship; and warrants to purchase 50,000 shares.
- (7) Includes 390,287 shares held as joint tenants with rights of survivorship.
- (8) Includes 322,245 shares are held by Mr. Howard's spouse, of which Mr. Howard disclaims beneficial ownership.
- (9) Includes 6,000 shares held by minor children.
- (10) Includes 15,667 shares subject to a currently exercisable stock option.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Certain Relationships and Related Transactions

Effective January 1, 2002, the Company's principal executive and administrative offices are located at 9870 Plano Road, Dallas, Texas, in offices that are owned by an affiliate that is controlled by Mr. Wallen. From July 1, 2010 through December 31, 2010 the offices were leased on a month-to-month basis for an average monthly amount charged to the Company of \$2,229, which was the same amount per month charged during all of fiscal 2010 and 2009. Effective, January 1, 2011, the Company signed a 2 year lease that charges the Company a monthly fee of \$8,000 per month. The Company believes that there is other appropriate space available in the event the Company should terminate its current leasing arrangement, though the Company believes the monthly rental fee would likely exceed \$8,000 per month.

Tauren owns a working interest in the wells in which the Company owns a working interest. The Company owed \$14,537, \$78,679 and \$649,205 to Tauren for miscellaneous general and administrative expenses and royalties for fiscal 2011, 2010 and 2009, respectively. Tauren owed the Company \$5,127 for royalties paid by a third-party operator for fiscal year 2011 and \$0 for fiscal 2010 and 2009.

In addition, during fiscal 2011, 2010 and 2009, certain wells in which the Company owns a working interest were operated by an affiliated company, Fossil Operating, Inc. ("Fossil"), an entity wholly owned by Mr. Wallen. In consideration for Fossil serving as operator and to satisfy the Company's working interest obligations related to drilling costs and lease operating expenses, Cubic paid to Fossil an aggregate of \$1,250,430, \$1,384,308 and \$4,244,397 during fiscal 2011, 2010 and 2009, respectively; and Fossil paid Cubic an aggregate of \$131,573, \$643,688 and \$151,680 during fiscal 2011, 2010 and 2009, respectively for oil and gas sales. As of June 30, 2011, 2010 and 2009, the Company owed Fossil \$43,143, \$755,683, and \$815,239, respectively, for drilling costs and lease operating expenses, and was owed by Fossil \$80,674, \$415,282, and \$271,615, respectively, for oil and gas sales. The Company and Fossil have operating agreements with respect to all wells for which Fossil serves as operator.

On May 6, 2008, the Company issued a subordinated promissory note in the amount of \$2,000,000 (the "Subordinated Note") to Diversified Dynamics Corporation (the "Lender"), an entity controlled by William Bruggeman, who beneficially owns more than 5% of the common stock of the Company. The Subordinated Note bore interest at a fluctuating rate equal to the sum of the prime rate plus two percent (2%) per annum, and was scheduled to mature on April 30, 2010. As consideration for the loan made by Lender pursuant to the Subordinated Note, the Company agreed to convey to Lender, upon the repayment in full of the

indebtedness evidenced by the Subordinated Note, an undivided 0.375% net profits interest in the future production of hydrocarbons from or attributable to Cubic's net interest in its Louisiana properties. The proceeds of the Subordinated Note were used for general corporate and working capital purposes. The Subordinated Note was repaid in December 2009 and the net profits interest was conveyed.

On November 24, 2009, the Company entered into transactions with Tauren and Langtry Mineral & Development, LLC ("Langtry"), both of which are entities controlled by Calvin Wallen III, the Chief Executive Officer of the Company, under which the Company has acquired \$30,952,810 in pre-paid drilling credits (the "Drilling Credits") applicable towards the development of its Haynesville Shale rights in Northwest Louisiana. The Company expects to use the Drilling Credits to fund \$30,952,810 of its share of the drilling and completion costs for those horizontal Haynesville Shale wells drilled in sections previously operated by an affiliate of the Company, which are now operated by a third party. As consideration for the Drilling Credits, the Company, (a) has conveyed to Tauren a net overriding royalty interest of approximately 2% in its leasehold rights below the Taylor Sand formation of the Cotton Valley and (b) has issued to Langtry 10,350,000 Company common shares and preferred stock in the amount of \$10,350,000, convertible into Company common shares at \$1.20 per common share, with a five year conversion term. The preferred stock is entitled to cumulative dividends equal to 8% per annum, payable quarterly, which dividends may be paid in cash or in additional shares of preferred stock, in the Company's discretion. As of June 30, 2011, the Company issued preferred stock in the amount of \$449,100 in lieu of cash dividends. The preferred stock may be redeemed by the Company at any time, at a redemption price equal to 20% over the original issue price. The consideration described above was determined based upon negotiations between Tauren and a Special Committee of the Company's directors, excluding Mr. Wallen. The Special Committee obtained a "fairness opinion" from its independent financial advisor with respect to the fairness, from a financial point of view, to the public stockholders of the Company, of such transactions.

On December 18, 2009, the Company issued a subordinated promissory note payable to Mr. Wallen, in the principal amount of \$2,000,000 (the "Wallen Note"). This note bears interest at the prime rate plus one percent (1%), with interest payable monthly. The Wallen Note was entered into with the consent of Wells Fargo and the outstanding principal balance is due and payable on September 30, 2012 and is subordinated to the indebtedness under the Amended Credit Agreement. The proceeds of this note were used to repay the Subordinated Note.

It is the Company's policy that any transactions between us and related parties will be on terms no less favorable than could be obtained from unaffiliated third parties and will be approved by a majority of the disinterested members of our Board of Directors.

Item 14. Principal Accountant Fees and Services.

	July 1, 2010 - June 30, 2011	July 1, 2009 - June 30, 2010
Audit fees	\$ 46,900	\$ 35,700
Audit-related fees	20,500	15,000
Tax fees	15,000	3,800
All other fees	1,000	13,060
Total	<u>\$ 83,400</u>	<u>\$ 67,560</u>

Audit Fees

Aggregate audit fees billed for professional services rendered by Philip Vogel & Co., PC were \$46,900 for the year ended June 30, 2011 and \$35,700 for the year ended June 30, 2010. Such fees were primarily for professional services rendered for the audits of our consolidated financial statements during the fiscal years ended June 30, 2011 and 2010.

Audit-Related Fees

Aggregate audit-related fees billed for professional services rendered by Philip Vogel & Co., PC were \$20,500 for the year ended June 30, 2011 and \$15,000 for the year ended June 30, 2010. Such fees were for limited reviews of our unaudited condensed consolidated interim financial statements.

Tax Fees

Aggregate income tax compliance and related services fees billed for professional services rendered by Philip Vogel & Co., PC were \$15,000, primarily Louisiana State income tax filing for the year ended June 30, 2011 and \$3,800 for the year ended June 30, 2010.

All Other Fees

In addition to the fees described above, aggregate fees of: \$1,000 were billed by Philip Vogel & Co., PC during the year ended June 30, 2011, primarily for the review of various SEC filings, and attendance at our annual stockholders' meeting; and \$13,060 were billed by Philip Vogel & Co., PC during the year ended June 30, 2010, primarily for the review of various SEC filings, attendance at our annual stockholders' meeting, and for research regarding our compliance with Section 404 of the Sarbanes-Oxley Act of 2002.

Audit Committee Pre-Approval Policies and Procedures

In accordance with Company policy, any additional audit or non-audit services must be approved in advance. All of the foregoing professional services provided by Philip Vogel & Co., PC during the years ended June 30, 2011 and June 30, 2010 were pre-approved in accordance with the policies of our Audit Committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) (1) and (2) Financial Statements and Financial Statement Schedules

See "Index to Financial Statements".

(a) (3) Exhibits

See the Exhibit Index immediately preceding the Exhibits filed with this report.

SIGNATURES

Pursuant to requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned; thereunto duly authorized, on September 28, 2011.

CUBIC ENERGY, INC.

By: /s/ Calvin A. Wallen, III

Calvin A. Wallen, III
President and Chief
Executive Officer

By: /s/ Larry G. Badgley

Larry G. Badgley
Chief Financial Officer

Pursuant to requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ Calvin A. Wallen, III</u> Calvin A. Wallen, III	Chairman, President and Chief Executive Officer (principal executive officer)	September 28, 2011
<u>/s/ Larry G. Badgley</u> Larry G. Badgley	Chief Financial Officer (principal financial and accounting officer)	September 28, 2011
<u>/s/ Jon S. Ross</u> Jon S. Ross	Secretary and Director	September 28, 2011
<u>/s/ Gene C. Howard</u> Gene C. Howard	Director	September 28, 2011
<u>/s/ Bob L. Clements</u> Bob L. Clements	Director	September 28, 2011
<u>/s/ David B. Brown</u> David B. Brown	Director	September 28, 2011
<u>/s/ Paul R. Ferretti</u> Paul R. Ferretti	Director	September 28, 2011
<u>/s/ Phyllis K. Harding</u> Phyllis K. Harding	Director	September 28, 2011
<u>/s/ William L. Bruggeman, Jr.</u> William L. Bruggeman, Jr.	Director	September 28, 2011

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CUBIC ENERGY, INC.

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JUNE 30, 2011

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Cubic Energy, Inc.,

We have audited the balance sheets of Cubic Energy, Inc., a Texas corporation, as of June 30, 2011 and 2010, and the related statements of operations, of changes in stockholders' equity and of cash flows for each of the three years in the period ended June 30, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these 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 audits 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 financial statements referred to above present fairly, in all material respects, the financial position of Cubic Energy, Inc. as of June 30, 2011 and 2010, and the results of its operations and its cash flows for each of the three years in the period ended June 30, 2011, in conformity with accounting principles generally accepted in the United States of America.

PHILIP VOGEL & CO. PC

Certified Public Accountants

Dallas, Texas

September 28, 2011

CUBIC ENERGY, INC.

**BALANCE SHEETS
JUNE 30, 2011 AND 2010**

	2011	2010
Assets		
Current assets:		
Cash and cash equivalents	\$ 1,542,248	\$ 391,898
Accounts receivable - trade	1,760,190	1,580,049
Due from affiliate	28,121	-
Other prepaid expenses	54,164	42,525
Total current assets	3,384,723	2,014,472
Property and equipment (at cost):		
Oil and gas properties, full cost method:		
Proved properties (including wells and related equipment and facilities)	25,606,874	14,852,010
Unproved properties	-	130,446
Office and other equipment	28,420	28,420
Oil and gas properties, and equipment, at cost	25,635,294	15,010,876
Less accumulated depreciation, depletion and amortization	9,795,293	6,088,038
Oil and gas properties, and equipment, net	15,840,001	8,922,838
Other assets:		
Deferred loan costs - net	68,554	39,471
Drilling credit	17,763,316	27,219,160
Total other assets	17,831,870	27,258,631
	\$ 37,056,594	\$ 38,195,941
Liabilities and stockholders' equity		
Current liabilities:		
Accounts payable and accrued expenses	\$ 1,065,103	\$ 3,031,300
Due to affiliates	-	419,080
Total current liabilities	1,065,103	3,450,380
Long-term liabilities:		
Long-term debt, net of discounts	29,196,541	18,983,532
Note payable to affiliate	2,000,000	2,000,000
Total long-term liabilities	31,196,541	20,983,532
Commitments and contingencies (Note H)	-	-
Stockholders' equity:		
Preferred stock - \$.01 par value, authorized 10,000,000 shares;		
Series A - 8% preferred stock, \$100 stated value, redeemable at \$120		
convertible at \$1.20 per common share, authorized 165,000 shares,		
107,991 shares issued and outstanding at June 30, 2011,		
and 103,500 issued and outstanding at June 30, 2010	\$ 1,080	\$ 1,035
Additional paid-in capital	10,798,020	10,348,965
Common stock - \$.05 par value, authorized 120,000,000 shares,		
issued 76,815,908 shares at June 30, 2011 and		
75,394,579 shares at June 30, 2010	3,840,797	3,769,730
Additional paid-in capital	55,695,730	54,032,985
Retained earnings' (deficit)	(65,540,677)	(54,390,686)
Total stockholders' equity	4,794,950	13,762,029
Total liabilities and stockholders' equity	\$ 37,056,594	\$ 38,195,941

The accompanying notes are an integral part of these statements.

CUBIC ENERGY, INC.

**STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED JUNE 30, 2011, 2010, AND 2009**

	2011	2010	2009
Revenues:			
Oil and gas sales	\$ 6,133,299	\$ 3,486,171	\$ 1,858,139
Total revenues	\$ 6,133,299	\$ 3,486,171	\$ 1,858,139
Operating costs and expenses:			
Oil and gas production, operating and development costs	1,857,528	1,845,153	1,372,041
General and administrative expenses	3,156,860	2,389,073	1,940,025
Depreciation, depletion and non-loan-related amortization	3,707,255	1,153,065	771,861
Impairment loss on oil and gas properties	-	-	20,390,819
Total operating costs and expenses	8,721,643	5,387,291	24,474,746
Operating income (loss)	(2,588,344)	(1,901,120)	(22,616,607)
Non-operating income (expense):			
Other income	8,098	4,540	33,544
Interest expense, including amortization of loan discount	(7,648,622)	(4,714,386)	(2,044,718)
Amortization of loan costs	(60,368)	(73,282)	(134,735)
Total non-operating income (expense)	(7,700,892)	(4,783,128)	(2,145,909)
Gain on debt extinguishment	-	1,747,623	-
Loss before income taxes	(10,289,236)	(4,936,625)	(24,762,516)
Provision for income taxes	-	-	-
Net loss	\$ (10,289,236)	\$ (4,936,625)	\$ (24,762,516)
Dividends on preferred shares	(860,755)	(240,000)	-
Net loss available to common shareholders	(11,149,991)	(5,176,625)	(24,762,516)
Net loss per common share - basic and diluted	\$ (0.15)	\$ (0.08)	\$ (0.40)
Weighted average common shares outstanding	76,048,925	67,583,793	61,150,400

The accompanying notes are an integral part of these statements.

CUBIC ENERGY, INC.

**STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED JUNE 30, 2011, 2010, AND 2009**

	Cumulative Preferred Stock		Additional paid-in capital	Common Stock		Additional paid-in capital	Accumulated deficit	Total stockholders' equity
	Shares Outstanding	Par Value		Shares Outstanding	Par Value			
Balance, June 30, 2008	-	\$ -	\$ -	58,853,064	\$ 2,942,654	\$ 27,366,690	\$ (24,451,145)	\$ 5,858,199
Stock issued under compensation plan	-			235,000	11,750	373,650	0	385,400
Stock issued for warrant exercise	-			3,482,500	174,125	2,321,827	0	2,495,952
Net loss, year ended June 30, 2009	-	\$ -	\$ -	0	0	0	(24,762,516)	(24,762,516)
Balance, June 30, 2009	-	\$ -	\$ -	<u>62,570,564</u>	<u>\$ 3,128,529</u>	<u>\$ 30,062,167</u>	<u>\$ (49,213,661)</u>	<u>\$ (16,022,965)</u>
Stock issued for working capital	-			2,104,001	105,200	1,683,200	0	1,788,400
Comm. Stock sold for property purchase	-			10,350,000	517,500	9,832,500	0	10,350,000
Pref. Stock sold for property purchase	103,500	1,035	10,348,965	0	0	0	0	10,350,000
Warrant valuations for loan extension	-			0	0	12,077,704	0	12,077,704
Stock issued under compensation plan	-			370,014	18,501	377,414	0	395,915
Preferred Stock Dividends	-			0	0	0	(240,400)	(240,400)
Net loss, year ended June 30, 2010	-			0	0	0	(4,936,625)	(4,936,625)
Balance, June 30, 2010	<u>103,500</u>	<u>\$ 1,035</u>	<u>\$ 10,348,965</u>	<u>75,394,579</u>	<u>\$ 3,769,730</u>	<u>\$ 54,032,985</u>	<u>\$ (54,390,686)</u>	<u>\$ 13,762,029</u>
Stock issued for warrant exercise	-			954,315	47,716	595,064	0	642,780
Pref. Stock issued for dividends	4,491	45	449,055	0	0	0	0	449,100
Warrant valuations for loan extension	-			0	0	516,882	0	516,882
Stock issued under compensation plan	-			467,014	23,351	519,268	0	542,619
Stock option compensation	-			0	0	31,531	0	31,531
Preferred Stock Dividends	-			0	0	0	(860,755)	(860,755)
Net loss, year ended Jun 30, 2011	-			0	0	0	(10,289,236)	(10,289,236)
Balance, Jun 30, 2011	<u>107,991</u>	<u>\$ 1,080</u>	<u>\$ 10,798,020</u>	<u>76,815,908</u>	<u>\$ 3,840,797</u>	<u>\$ 55,695,730</u>	<u>\$ (65,540,677)</u>	<u>\$ 4,794,950</u>

The accompanying notes are an integral part of these statements.

CUBIC ENERGY, INC.

**STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED JUNE 30, 2011, 2010, AND 2009**

	2011	2010	2009
Cash flows from operating activities:			
Net (loss)	\$(10,289,236)	\$ (4,936,625)	\$ (24,762,516)
Adjustments to reconcile net (loss) to cash provided (used) by operating activities:			
Depreciation, depletion and amortization	9,508,063	4,404,763	1,421,216
Impairment loss	-	-	20,390,819
Gain on extinguishment of debt	-	(1,747,623)	-
Stock issued for compensation	574,150	395,915	385,400
Change in assets and liabilities:			
(Increase) decrease in accounts receivable - trade	(180,141)	(1,379,099)	(35,040)
(Increase) decrease in other prepaid expenses	(11,639)	12,538	10,280
Increase (decrease) in accounts payable and accrued liabilities	(1,964,987)	2,491,519	48,751
Increase (decrease) in due to affiliates	(203,369)	76,899	388,903
Net cash (used) by operating activities	(2,567,159)	(681,713)	(2,152,187)
Cash flows from investing activities:			
Acquisition and development of oil and gas properties	(1,168,574)	(5,032,312)	(6,001,210)
Increase (decrease) in capital portion of due to affiliates	(243,832)	(850,647)	392,642
Purchase of office equipment	-	-	(13,748)
(Increase) decrease in advances on development costs	-	-	33,399
(Increase) decrease in other assets	-	147,120	-
Net cash (used) by investing activities	(1,412,406)	(5,735,839)	(5,588,917)
Cash flows from financing activities:			
Issuance of common stock, net	642,780	1,788,400	2,495,952
Proceeds from credit facility	5,000,000	5,000,000	3,172,200
Dividends paid	(412,865)	-	-
Loan costs incurred and other	(100,000)	(50,000)	-
Net cash provided by financing activities	5,129,915	6,738,400	5,668,152
Net increase (decrease) in cash and cash equivalents	\$ 1,150,350	\$ 320,848	\$ (2,072,952)
Cash and cash equivalents:			
Beginning of year	391,898	71,050	2,144,002
End of year	\$ 1,542,248	\$ 391,898	\$ 71,050
Other information:			
Cash interest paid on debt	\$ 1,891,828	\$ 1,548,685	\$ 1,560,759
Non-cash investing and financing activities:			
Common and preferred stock for drilling credits	\$ -	\$ 20,700,000	\$ -
Property interest assigned for drilling credits	\$ -	\$ 10,252,810	\$ -
Equity interest issued creating a deferred interest from debt modification	\$ -	\$ 12,077,704	\$ -
Preferred stock dividends accrued	\$ 860,755	\$ 240,400	\$ -
Use of prepaid drilling credits	\$ 9,455,844	\$ -	\$ -
Warrants issued for loan costs	\$ 516,882	\$ -	\$ -
Conversion of accrued Preferred stock dividend	\$ 449,100	\$ -	\$ -

The accompanying notes are an integral part of these statements.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Note A - Background and general:

Cubic Energy, Inc. (the “Company”) is engaged in domestic crude oil, natural gas and natural gas liquids exploration, development and production, with primary emphasis on the production of oil and gas reserves through the acquisition and development of proved, producing oil and gas properties in the states of Texas and Louisiana.

Note B - Significant accounting policies:

Cash equivalents

For purposes of the statements of cash flows, the Company considers all certificates of deposit and other financial instruments with original maturity dates of three months or less to be cash equivalents.

Accounts Receivable

The Company has receivables from affiliated and non-affiliated third-party operators and oil and gas purchasers that are generally uncollateralized. The Company reviews these parties for creditworthiness and general financial condition. Accounts receivable are generally due within 30 days and accounts outstanding longer than 60 days are considered past due. If necessary, the Company would determine an allowance by considering the length of time past due, previous loss history and the owners ability to pay its obligation, among other things. The Company writes off accounts receivable when they are determined to be uncollectible.

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary using the specific identification method. There was no allowance for doubtful accounts at June 30, 2011, 2010 and 2009.

Office and other equipment

Office and other equipment are stated at cost and depreciated by the straight-line method over estimated useful lives ranging from five to seven years. Depreciation and amortization of office and other equipment amounted to \$4,070, \$5,193 and \$5,193 for the years ended June 30, 2011, 2010 and 2009, respectively.

Impairment of long-lived assets and long-lived assets to be disposed of

The Company follows the provisions of Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) Topic 360-10, Property, Plant and Equipment – Impairment or Disposal of Long-Lived Assets, which provides guidance for the financial accounting and reporting of impairment or disposal of long-lived assets. In addition, the Company is subject to the rules of the Securities and Exchange Commission with respect to impairment of oil and gas properties accounted for under the full cost method of accounting, as described below.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Full cost method of accounting for oil and gas properties

The Company has adopted the full cost method of accounting for oil and gas properties. Management believes adoption of the full cost method more accurately reflects management's exploration objectives and results by including all costs incurred as integral for the acquisition, discovery and development of whatever reserves ultimately result from its efforts as a whole. Under the full cost method of accounting, all costs associated with acquisition, exploration and development of oil and gas reserves, including such costs as leasehold acquisition costs, interest costs related to exploratory and development activities, and directly related overhead costs, are capitalized into the full cost pool.

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized.

In addition, the capitalized costs are subject to a "full cost ceiling test," which generally limits such costs to the aggregate of the "estimated present value" (discounted at a 10 percent (10%) interest rate) of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties. Accordingly, no impairment of oil and gas properties charge was recorded for fiscal 2011, no impairment charge was recorded in fiscal 2010 and an impairment charge of \$20,390,819 was recorded in fiscal 2009.

Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas, in which case the gain or loss is recognized in income.

Depletion of producing oil and gas properties amounted to \$3,703,185, \$1,147,872 and \$766,668 for the years ended June 30, 2011, 2010 and 2009, respectively.

Income taxes

Income taxes are accounted for 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 basis. Deferred tax assets and liabilities are measured using enacted tax rates that will apply in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

Under ASC No. 740, Income Tax Consequences of Issuing Convertible Debt with a Beneficial Conversion Feature, the issuance of convertible debt with a beneficial conversion feature results in a temporary difference for purposes of applying ASC No. 740. The deferred taxes recognized for the temporary difference should be recorded as an adjustment to paid-in capital. ASC No. 740 requires that the non-detachable conversion feature of a convertible debt security be accounted for separately if it is a "beneficial conversion feature."

CUBIC ENERGY, INC.

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A beneficial conversion feature is recognized and measured by allocating to additional paid-in capital a portion of the proceeds equal to the conversion feature's intrinsic value. A discount on the convertible debt is recognized for the amount that is allocated to additional paid-in capital. The debt discount is accreted from the date of issuance to the stated redemption date of the convertible instrument or through the earliest conversion date if the instrument does not have a stated redemption date. The U.S. Internal Revenue Code includes the entire amount of proceeds received at issuance as the tax basis of the convertible debt security. ASC No. 740 requires that the Company recognize in the financial statements the impact of a tax position if that position is more likely than not of being sustained upon audit, based on the technical merits of the position. The adoption of ASC No. 740 has had no impact on the Company's financial statements.

The Company is no longer subject to income tax examinations by the Internal Revenue Service for years prior to 2008.

Oil and gas revenues

The Company recognizes oil and gas revenues when oil and gas production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a purchaser's pipeline or truck. As a result of the numerous requirements necessary to gather information from purchasers or various measurement locations, calculate volumes produced, perform field and wellhead allocations and distribute and disburse funds to various working interest and royalty owners, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production. Since the settlement process may take 30 to 60 days following the month of actual production, our financial results include estimates of production and revenues for the related time period. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized. Due to increased numbers of third-party operated Haynesville Shale wells, differences between sales and production volumes increased 76% from fiscal 2010 to fiscal 2011, and increased 184% from fiscal 2009 to fiscal 2010.

Earnings (loss) per common share

The Company has adopted the provisions of ASC No. 260, Earnings per Share. ASC No. 260 requires the presentation of basic earnings (loss) per share ("EPS") and diluted EPS. Basic EPS is calculated by dividing net income or loss less preferred dividends (income available to common stockholders) by the weighted average number of common shares outstanding for the period. Diluted EPS is calculated by dividing net income or loss less preferred dividends (income available to common stockholders) by the weighted average number of common shares outstanding plus any dilutive shares (i.e., preferred dividends, stock warrants or other convertible debt) during the period.

As discussed in Note D, there were no dilutive securities outstanding during the years ended June 30, 2011, 2010 and 2009. The weighted average number of common and common equivalent shares outstanding was 76,048,925, 67,583,793 and 61,150,400 for the years ended June 30, 2011, 2010 and 2009, respectively.

CUBIC ENERGY, INC.

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Concentration of customers and credit risk

Financial instruments which potentially subject the Company to a concentration of credit risk consist primarily of trade accounts receivable with a variety of local, national, and international oil and natural gas companies. Such credit risks are considered by management to be limited due to the financial resources of the oil and natural gas companies.

Our money market account, which is an interest bearing account and only FDIC insured to a balance of \$250,000, had a balance of \$1,329,199 as of June 30, 2011. This leaves approximately \$1,079,199 as a credit risk to the Company.

Our revenue of \$6,133,299 was partially generated by three producers with over 10% of that total. They are as follows: Goodrich totaled \$790,667 or 13%, Chesapeake totaled \$812,838 or 14%, and EXCO totaled \$3,890,861 or 66%.

As noted earlier the Company has receivables from non-affiliated operators for oil and gas sales. It also has accounts payable to such operators for its share of development, production, and operating costs. As of June 30, 2011, a single operator owed the Company approximately \$835,565 which is included in accounts receivable. Receipt of these obligations will be made upon resolution of matters relating to the exact division of ownership interests among the Company and its affiliates. Revenues attributed to this operator amounted to approximately \$812,838 for the year ended June 30, 2011.

Reporting comprehensive income (loss) and operating segments

The Company has adopted the provisions of ASC No. 220, Comprehensive Income, and ASC No. 280, Segment Reporting. ASC No. 220 requires that an enterprise report, by major components and as a single total, the change in its net assets during the period from non-owner sources. ASC No. 280 establishes annual and interim reporting standards for an enterprise's operating segments and related disclosures about its products, services, geographic areas and major customers. Adoption of ASC No. 220 and ASC No. 280 has had no impact on the Company's financial position, results of operations, cash flows, or related disclosures because the Company's operations are considered to be a single segment.

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 amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Certain significant estimates

Management's estimates of oil and gas reserves are based on various assumptions, including constant oil and gas prices. It is reasonably possible that a future event in the near term could cause the estimates to change and such changes could have a severe impact. Actual future production, cash flows, taxes, operating expenses, development expenditures and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimate. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves. While it is at least reasonably possible that the estimates above will change materially in the near term, no estimate can be made of the range of possible changes that might occur.

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CUBIC ENERGY, INC.

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Fair value of financial instruments

The Company has adopted the provisions of ASC No. 825, Financial Instruments. ASC No. 825 allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. ASC No. 825 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities.

The Company defines the fair value of a financial instrument as the amount at which the instrument could be exchanged in a current transaction between willing parties. Financial instruments included in the Company's financial statements include cash and cash equivalents, short-term investments, accounts receivable, other receivables, other assets, accounts payable, notes payable and due to affiliates. Unless otherwise disclosed in the notes to the financial statements, the carrying value of financial instruments is considered to approximate fair value due to the short maturity and characteristics of those instruments. The carrying value of debt approximates fair value as terms approximate those currently available for similar debt instruments.

Asset retirement obligations

We have asset retirement obligations primarily for the future abandonment of oil and gas wells, and we maintain reserve accounts for part of these obligations under our operating agreements with sponsored drilling partnerships. We account for these obligations under ASC No. 410-20, Asset Retirement and Environmental Obligations, which requires the fair value of an asset retirement obligation to be recognized in the period when it is incurred if a reasonable estimate of fair value can be made. The present value of the estimated asset retirement cost is capitalized as part of the carrying amount of the underlying long-lived asset. ASC No. 410-20 also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. The depreciation is generally determined on a units-of-production basis over the life of the asset, while the accretion escalates over the life of the asset, typically as production declines. The amounts recognized are based on numerous estimates and assumptions, including recoverable quantities of oil and gas, future retirement and site reclamation costs, inflation rates and credit-adjusted risk-free interest rates.

Stock-based compensation

The Company accounts for its stock-based employee compensation plans pursuant to ASC No. 718, Stock Compensation. ASC No. 718 requires the Company to recognize compensation costs related to stock-based payment transactions (i.e., the granting of stock options and warrants, and awards of shares of common stock) in the financial statements. With limited exceptions, the amount of compensation is measured based on the grant-date fair value of the equity issued. Compensation cost is recognized over the period that an employee provides services in exchange for the award.

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Exit or disposal activities

The Company has adopted the provisions of ASC No. 420, Exit or Disposal Cost Obligations. ASC No. 420 requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operations, or other exit or disposal activities. No exit or disposal activities have been entered into by the Company.

Financial instruments with characteristics of both liabilities and equity

The Company has adopted the provisions of ASC No. 480, Distinguishing Liabilities from Equity. ASC No. 480 established standards for how a company classifies and measures certain financial instruments with characteristics of both liabilities and equity. The statement requires that a company classify a financial instrument that is within its scope as a liability (or an asset in some circumstances) if certain criteria are met. Freestanding financial instruments that obligate the issuer to redeem the holder's shares, or are indexed to such an obligation, and are settled in cash or settled with shares meeting certain conditions would be treated as liabilities. Many of those instruments were previously classified as equity.

ASC No. 480-10-05, Distinguishing Liabilities from Equity, clarifies that freestanding warrants and similar instruments on shares that are redeemable should be accounted for as liabilities under ASC No. 480 regardless of the timing of the redemption feature or price, even though the underlying shares may be classified as equity. Although the Company had outstanding warrants as of June 30, 2011, the shares issuable upon exercise of the warrants are not redeemable; consequently, adoption of ASC No. 480 has not had an impact on the Company's financial position, results of operations or cash flows.

Guarantee of debt

The Company has adopted the provisions of ASC No. 460, Guarantees. ASC No. 460 clarifies that a guarantor is required to recognize, at the inception of certain types of guarantees, a liability for the fair value of the obligation undertaken in issuing the guarantee, and requires additional disclosures on existing guarantees even if the likelihood of future liability under the guarantees is deemed remote. The Company has not issued any guarantees and, therefore, the adoption of ASC No. 460 has not had any impact on the Company's financial statements.

Accounting changes and error corrections

The Company has adopted the provisions of ASC No. 250, Accounting Changes and Error Corrections. ASC No. 250 applies to all voluntary changes in accounting principles and changes required by an accounting pronouncement in the unusual instance that the pronouncement does not include specific transition provisions. Under previous guidance, changes in accounting principle were recognized as a cumulative effect in the net income of the period of the change. ASC No. 250 requires retrospective application of changes in accounting principle, limited to the direct effects of the change, to prior periods' financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change in accounting principle. The adoption of ASC No. 250 did not have a material impact on the Company's financial position, results of operations or cash flows.

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Debt modifications

The Company has adopted the provisions of ASC No. 470, Debt Modifications and Extinguishment. ASC No. 470 requires an issuer that modifies a debt instrument to compare the present value of the original debt instrument's cash flows to the present value of the cash flows of the modified debt. If the present value of those cash flows varies by more than 10 percent (10%), the modification is considered significant and extinguishments accounting is applied to the original debt. If the change in the present value of the cash flows is less than 10 percent (10%), the debt is considered to be modified and is subject to ASC No. 470 modification accounting. ASC No. 470 requires that in applying the 10 percent (10%) test the change in the fair value of the conversion option be treated in the same manner as a current period cash flow. ASC No. 470 also requires that, if a modification does not result in an extinguishment, the change in fair value of the conversion option be accounted for as an adjustment to interest expense over the remaining term of the debt. The issuer should not recognize a beneficial conversion feature or reassess an existing beneficial conversion feature upon modification of the conversion option of a debt instrument that does not result in an extinguishment. The adoption of ASC No. 470 did not have a material impact on the Company's financial position, results of operations or cash flows.

Certain hybrid financial instruments

The Company has adopted the provisions of ASC No. 815, Derivatives and Hedging. ASC No. 815 improves the financial reporting of certain hybrid financial instruments by requiring more consistent accounting that eliminates exemptions and provides a means to simplify the accounting for these instruments. Specifically, ASC No. 815 allows financial instruments that have embedded derivatives to be accounted for as a whole (eliminating the need to bifurcate the derivative from its host) if the holder elects to account for the whole instrument on a fair value basis. The adoption of ASC No. 815 did not have a material impact on the Company's financial position, results of operations or cash flows.

Reporting taxes collected

The Company has adopted the provisions of ASC No. 605, Taxes Collected from Customers and Remitted to Governmental Authorities. Taxes collected should be presented in the income statement (gross versus net presentation). ASC No. 605 addresses income statement classification and disclosure requirements of externally-imposed taxes on revenue-producing transactions. The adoption of ASC No. 605 did not have a material impact on the Company's financial position, results of operations or cash flows.

Subsequent Events

The Company has adopted the provisions of ASC No.855, Subsequent Events. ASC No. 855 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. ASC No. 855 sets forth (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The adoption of ASC No. 855 did not have a material effect on the Company's financial position, results of operations or cash flows.

CUBIC ENERGY, INC.

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Other recent accounting pronouncements

In February 2010, the FASB issued Accounting Standards Update (“ASU”) 2010-09, Amendments to Certain Recognition and Disclosure Requirements, amending its guidance on subsequent events under ASC No. 855 to remove the requirement for SEC filers to disclose the date through which events or transactions occurring after the balance sheet date have been evaluated for potential recognition or disclosure. ASU 2010-09 was effective for the first reporting period after its issuance. ASC No. 855 became effective in June 2009, and its adoption did not affect our practices for evaluating, recording or disclosing subsequent events.

In January 2010, the FASB issued ASU No. 2010-03, Extractive Industries—Oil and Gas (Topic 932) — Oil and Gas Reserve Estimation and Disclosures. This ASU aligns industry-specific accounting standards for oil and gas producing activities with revised oil and gas reserve estimation and disclosure rules adopted by the SEC at the end of 2008 and subsequently consolidated in Subpart 1200 of Regulation S-K and amendments to Rule 4-10 of Regulation S-X under the Exchange Act. We adopted the revised standards and reserve reporting rules on December 31, 2009.

In August 2009, the FASB issued ASU 2009-05, Fair Value Measurements and Disclosures — Measuring Liabilities at Fair Value, which provides clarification for the fair value measurement of liabilities, effective for the first reporting period after issuance. Our adoption of this update did not have a significant impact on our financial position, results of operations, cash flows or disclosures.

ASC 105, Generally Accepted Accounting Principles was issued by the FASB in July 2009 to establish the ASC as the single source of authoritative nongovernmental GAAP, except for SEC rules and interpretive releases. Under ASC 105, the Codification became effective for reporting periods ended after September 15, 2009. The Codification did not change existing GAAP, and adoption of ASC 105 did not have any impact on our consolidated financial statements.

Note C – Stockholders’ equity:

The Company's authorized capital is 120,000,000 shares of \$0.05 par value common stock and 10,000,000 shares of \$0.01 par value preferred stock. 107,991 shares of preferred stock were issued and outstanding at June 30, 2011 and 103,500 shares of preferred stock were issued and outstanding at June 30, 2010.

Stock and warrants

On December 16, 2005, the Company entered into a Securities Purchase Agreement and issued 2,500,000 common shares at a price of \$0.80 per share and issued warrants, with five year expirations, for the purchase of up to 1,000,000 shares of Company common stock at an exercise price of \$1.00 per share. The proceeds of the offering were used for exploratory drilling and working capital. 897,500 of the above-referenced warrants had been exercised and the remaining 102,500 expired at June 30, 2011.

On February 6, 2006, Cubic entered into a Credit Agreement with Petro Capital V, L.P. (“Petro Capital”) pursuant to which Petro Capital advanced to the Company \$5,500,000. In connection with the funding under the Credit Agreement, the Company issued to Petro Capital and Petro Capital Securities, LLC, warrants, with five-year expirations, for the purchase of up to 1,833,334 and 250,000 shares, respectively, of Company common stock at an exercise price of \$1.00 per share. Pursuant to the anti-dilution adjustment provisions applicable to such warrants, the exercise price applicable to all such warrants still

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outstanding is currently \$0.9651 per share. 1,550,000 of the above-referenced warrants issued to Petro Capital had been exercised as of June 30, 2010, and the 283,334 remaining were exercised during the year ended June 30, 2011.

On July 28, 2006, Cubic entered into and consummated transactions pursuant to Subscription and Registration Rights Agreements (the "July 2006 Subscription Agreements") with certain investors that are unaffiliated with the Company. Pursuant to the Subscription Agreements, the investors paid aggregate consideration of \$2,100,000 to the Company for 3,000,000 shares of the Company's common stock and warrants exercisable, through July 31, 2011, into 1,500,000 shares of common stock at \$0.70 per share. Pursuant to the anti-dilution adjustment provisions applicable to such warrants, the exercise price applicable to all such warrants is currently \$0.6849 per share. 1,125,000 of the above-referenced warrants had been exercised and 375,000 remain outstanding at June 30, 2011.

On December 15, 2006, the Company entered into Subscription and Registration Rights Agreements (the "December 2006 Subscription Agreements") with certain investors. One of the investors, William Bruggeman (and entities affiliated with him) was the beneficial owner, prior to this transaction, of approximately 23.0% of the common stock of the Company. In this transaction, Mr. Bruggeman (and entities affiliated with him) purchased an aggregate of 4,288,000 shares of common stock at a purchase price of \$0.50 per share, or an aggregate of \$2,144,000. Mr. Bruggeman (and entities affiliated with him) received warrants to purchase 2,144,000 shares of common stock with an exercise price of \$0.70 per share.

Another investor, Bob Clements, a director of the Company, purchased 100,000 shares of common stock at a purchase price of \$0.50 per share, or an aggregate of \$50,000. Mr. Clements received warrants to purchase 50,000 shares of common stock with an exercise price of \$0.70 per share. Pursuant to the December 2006 Subscription Agreements, the investors paid aggregate consideration of \$3,940,000 to the Company for 7,880,000 shares of the Company's common stock and warrants exercisable into 3,940,000 shares of common stock. The warrants are exercisable through November 30, 2011, at \$0.6963 per share. 2,840,000 of the above-referenced warrants have been exercised and 1,100,000 remained outstanding at June 30, 2011.

On March 5, 2007, Cubic entered into a Credit Agreement with Wells Fargo Energy Capital ("Wells Fargo") providing for a revolving credit facility of \$20,000,000 and a convertible term loan of \$5,000,000 (the "Credit Facility"). In connection with entering into the Credit Facility, the Company issued to Wells Fargo warrants, with five-year expirations, for the purchase of up to 2,500,000 shares of Company common stock at an exercise price of \$0.9911 per share. The term loan is also convertible into 5,044,900 shares of Company common stock at a conversion price of \$0.9911 per share. None of the above-referenced warrants had been exercised and all remained outstanding at June 30, 2011. The Company allocated the proceeds from the issuance of the debt to the warrants, the debt and net profits interest (see "Note E – Long-term debt") based on their relative fair market values at the date of issuance. The value assigned to the warrants of \$1,314,289 was recorded as an increase in additional paid-in capital and the value assigned to the net profits interest of \$213,148 was recorded as a credit to the full cost pool for oil and gas properties.

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On December 18, 2009, the Company entered into a Second Amendment to the Credit Agreement with Wells Fargo, providing for a revolving credit facility of up to \$40 million and a convertible term loan of \$5 million (the "Amended Credit Agreement"). The borrowing base under the revolving credit facility was initially established at \$25 million. The indebtedness bears interest at a fluctuating rate equal to the sum of the Wells Fargo Bank prime rate plus two percent (2%) per annum, matures on July 1, 2012 and is secured by substantially all of the assets of the Company. In connection with entering into the Amended Credit Agreement, the Company issued to Wells Fargo additional warrants, expiring on December 1, 2014, for the purchase of up to 5,000,000 shares of Company common stock, currently at an exercise price of \$0.9911 per share, and extended the expiration date of the warrants to purchase 2,500,000 shares of Company common stock that were previously issued to Wells Fargo to December 1, 2014.

On August 30, 2010, the Company entered into a Third Amendment to the Credit Agreement (the "Third Amendment") with Wells Fargo providing for an increase in the borrowing base for the Company's revolving credit facility from \$25 million to \$30 million. The Company borrowed the full amount of the increase in the borrowing base. The indebtedness under the credit facility, which includes the revolving credit facility and a \$5 million convertible term loan, bears interest at a fluctuating rate equal to the sum of the Wells Fargo Bank prime rate plus two percent (2%) per annum, matures on July 1, 2012 and is secured by substantially all of the assets of the Company. In connection with entering into the Third Amendment, the Company issued to Wells Fargo additional warrants, expiring on December 1, 2014, for the purchase of up to 1,000,000 shares of the Company's common stock at an exercise price of \$1.00 per share. Loan costs of \$89,451 and loan discounts of \$527,430 were recognized.

Through the following exercises of warrants, we issued an aggregate of 3,482,500 shares of common stock, which were not registered under the Securities Act of 1933, as amended, during fiscal 2009:

On July 3, 2008, two warrant holders of the Company exercised warrants for an aggregate of 1,127,500 shares of Company common stock, through the payment of \$777,002 to the Company.

On July 7, 2008, one warrant holder of the Company exercised warrants for 250,000 shares of Company common stock, through the payment of \$243,950 to the Company.

On July 8, 2008, one warrant holder of the Company exercised warrants for 100,000 shares of Company common stock, through the payment of \$70,000 to the Company.

On July 17, 2008, one warrant holder of the Company exercised warrants for 5,000 shares of Company common stock, through the payment of \$5,000 to the Company.

On February 23, 2009, twenty-two warrant holders of the Company exercised warrants for 2,000,000 shares of Company common stock, through the payment of \$1,400,000 to the Company. Included among these warrant holders were the following 5% beneficial owners: William L. Bruggeman, Jr. and Ruth J. Bruggeman JTWROS exercised warrants for 1,544,000 shares and Steven S. Bruggeman exercised warrants for 24,000 shares.

Aggregate proceeds to the Company of the aforementioned stock issuances were \$2,495,952, all of which have been used for working capital purposes.

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In connection with the following common stock issuances, the Company entered into Subscription and Registration Rights Agreements (“Subscription Agreements”) with certain investors. Pursuant to the Subscription Agreements, the Company issued an aggregate of 2,104,001 shares of common stock and warrants exercisable into 1,052,000 shares of common stock. On August 18, 2009, four investors acquired 804,000 shares of common stock and warrants exercisable into 402,000 shares of common stock, through the payment of \$683,400. On August 26, 2009, six investors acquired 1,300,001 shares of common stock and warrants exercisable into 650,000 shares of common stock, through the payment of \$1,105,001. The warrants are exercisable through July 31, 2014, at \$0.85 per share. With respect to certain of such issuances, the Company paid broker-dealer commissions in the aggregate amount of \$59,500 to Avalon Group, Ltd. The aggregate consideration, net of commissions, from such issuances has been used for working capital purposes. Warrants for 264,706 shares of common stock were exercised during 2011, and 787,194 warrants remain outstanding at June 30, 2011.

As consideration for the Drilling Credits, the Company (a) conveyed to Tauren a net overriding royalty interest of approximately 2% in its leasehold rights below the Taylor Sand formation of the Cotton Valley and (b) on March 16, 2010 issued to Langtry 10,350,000 Company common shares and preferred stock with a stated value of \$10,350,000, convertible into Company common shares at \$1.20 per common share, with a five year conversion term. The preferred stock is entitled to cumulative dividends equal to 8% per annum, payable quarterly, which dividends may be paid in cash or in additional shares of preferred stock, in the Company's discretion. The preferred stock may be redeemed by the Company at any time, at a redemption price equal to 20% over the original issue price, plus accrued and unpaid dividends.

Stock-based compensation

On December 29, 2005, the stockholders of the Company approved the 2005 Stock Option Plan (the "Plan") and 3,750,000 shares of common stock were reserved, of which 2,558,139 shares had been issued through June 30, 2011. At the 2010 Annual Stockholder Meeting stockholders approved an increase in the number of shares under the Plan by 2,000,000 shares. Total shares available under the Plan are 2,558,139 as of June 30, 2011.

On January 12, 2009, the Company issued 235,000 shares to three directors of the Company pursuant to the Plan. As of such dates, the aggregate market value of the common stock granted was \$385,400 based on the last sale price (\$1.64 per share) on the aforementioned date, on the AMEX of the Company's common stock. Such amounts were expensed upon issuance to compensation expense.

On February 3, 2010, the Company issued 370,014 shares to five directors of the Company pursuant to the Plan. As of such dates, the aggregate market value of the common stock granted was \$395,915 based on the last sale price (\$1.07 per share) on the aforementioned date, on the AMEX of the Company's common stock. Such amounts were expensed upon issuance to compensation expense.

On November 30, 2010, the Board of Directors increased the number of directors of the Company and appointed David B. Brown and Paul R. Ferretti to fill the vacancies created by such increase, in accordance with the provisions of the Company's bylaws. The Board authorized stock grants of 3,507 shares of common stock to each of Messrs. Brown and Ferretti, which number of shares is equal to the number of shares granted to other non-management directors for calendar year 2010, on a prorated basis, with an aggregate market value of the common stock granted of \$4,418 based on at the last sale price (\$0.63 per share) on the aforementioned date, on the AMEX of the Company's common stock. Such amounts were recorded as compensation expense upon issuance.

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On January 14, 2011, the Company entered into an employment agreement with its Chief Financial Officer, Larry G. Badgley. The agreement provides for the grant of stock options, under the Plan, for the purchase of an aggregate of 288,667 shares of Company common stock. These options have an exercise price \$1.20 per share and expire five years from their issue date. One option, for the purchase of 15,667 shares, was fully vested upon grant. The other option, for the purchase of 273,000 shares shall, subject to the other provisions of the option agreement, vest upon the earliest of: (a) immediately prior to a Change in Control (as defined in the Plan), (b) October 1, 2012, provided that Mr. Badgley's Continuous Service (as defined in the Plan) continues through October 1, 2012, (c) the termination by Mr. Badgley of his Continuous Service prior to October 1, 2012 in compliance with the terms of a then-effective written employment agreement between him and the Company or an affiliate of the Company or (d) the termination by the Company of Mr. Badgley's Continuous Service prior to October 1, 2012, other than for Just Cause (as defined in the employment agreement). We estimated the fair value of the options on the date of grant using the Black-Scholes valuation model to be \$100,997. We recorded \$31,531 of compensation expense for the year ending June 30, 2011 and estimate that approximately \$13,025 will be recognized quarterly until the options are fully vested on October 1, 2012.

The weighted-average fair value at the grant date using the Black-Scholes valuation model for options issued during fiscal 2011 was \$0.35 per share. The fair value of options at the date of grant was estimated using the following weighted-average assumptions for fiscal 2011: (a) no dividend yield on our common stock, (b) expected stock price volatility of 73%, (c) a discount rate of 2.04% and (d) an expected option term of 5 years.

The expected term of the options represents the estimated period of time until exercise and is based on consideration to the contractual terms, vesting schedules and expectations of future employee behavior. For fiscal 2011, expected stock price volatility is based on the historical volatility of our common stock.

The risk-free interest rate is based on the U.S. Treasury bill rate in effect at the time of grant with an equivalent expected term or life.

Information regarding activity for stock options under the Plan is as follows:

	Number of shares	Weighted- average exercise price per share	Weighted average remaining contractual term (years)	Aggregate intrinsic value
Outstanding, June 30, 2010	-	\$ -		
Options granted	288,667	1.20		
Options exercised	-	-		
Options forfeited/expired	-	-		
Outstanding, June 30, 2011	288,667	1.20	4.5	-
Exercisable, June 30, 2011	15,667	1.20	4.5	-

Information related to the Plan during fiscal June 30, 2011 is as follows:

Intrinsic value of options exercised	\$	-
Weighted-average fair value of options granted	\$	100,997

On January 18, 2011, the Company issued 460,000 unregistered shares of common stock to seven directors of the Company pursuant to the Plan. As of such date, the aggregate market value of the common stock granted was \$538,200 based on the last sale price (\$1.17 per share) on January 11, 2011, on the AMEX of the Company's common stock. Such amount was expensed upon issuance to compensation expense.

The following table provides information related to stock-based compensation for the years ended June 30, 2011, 2010 and 2009:

	Fiscal Year Ended June 30,		
	2011	2010	2009
Officer and employee restricted stock grants:			
Pretax compensation expense	\$ -	\$ -	\$ 12,938
Tax benefit	\$ -	\$ -	\$ -
Restricted stock expense, net of tax	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 12,938</u>
Director restricted stock grants:			
Pretax compensation expense	\$ 542,619	\$ 395,915	\$ 385,400
Tax benefit	\$ -	\$ -	\$ -
Director stock grants expense, net of tax	<u>\$ 542,619</u>	<u>\$ 395,915</u>	<u>\$ 385,400</u>
Stock options:			
Pretax compensation expense	\$ 31,531	\$ -	\$ -
Tax benefit	\$ -	\$ -	\$ -
Stock option expense, net of tax	<u>\$ 31,531</u>	<u>\$ -</u>	<u>\$ -</u>
Total stock-based compensation:			
Pretax compensation expense	\$ 574,150	\$ 395,915	\$ 398,338
Tax benefit	\$ -	\$ -	\$ -
Total share based compensation expense, net of tax	<u>\$ 574,150</u>	<u>\$ 395,915</u>	<u>\$ 398,338</u>

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Note D – Loss per common share:

	<u>2011</u>	<u>2010</u>	<u>2009</u>
Net loss attributable to common stockholders	\$ (11,149,991)	\$ (5,176,625)	\$ (24,762,516)
Weighted average number of shares of common stock	76,048,925	67,583,793	61,150,400
Income (loss) per common share	\$ (0.15)	\$ (0.08)	\$ (0.40)

Potential dilutive securities (e.g., convertible preferred stock, stock warrants and convertible debt) have not been considered because the Company reported a net loss and, accordingly, their effects would be anti-dilutive.

Note E – Long-term debt:

March 2007 debt issue

On March 5, 2007, Cubic entered into a Credit Agreement with Wells Fargo Energy Capital, Inc. (“Wells Fargo”) providing for a revolving credit facility of \$20,000,000 (the “Revolving Note”) and a convertible term loan of \$5,000,000 (the “Term Loan”; and together with the Revolving Note, the “Credit Facility”). The indebtedness bore interest at a fluctuating rate equal to the sum of the Wells Fargo Bank prime rate plus two percent (2%) per annum, was originally scheduled to mature on March 1, 2010, and was secured by substantially all of the assets of the Company.

The Term Loan of \$5,000,000 is convertible into 5,000,000 shares of Cubic common stock, currently at a conversion price of \$0.9911 per share. Approximately \$5,000,000 of the funded amount was used, together with cash on hand, to retire the Company’s previously outstanding senior debt that was due February 6, 2009.

In connection with entering into the Credit Facility, the Company issued to Wells Fargo warrants, with five-year expirations, for the purchase of up to 2,500,000 shares of Company common stock, currently at an exercise price of \$0.9911 per share.

The Company allocated the proceeds from the issuance of the debt to the warrants, the debt and net profits interest in the future production of hydrocarbons from or attributable to Cubic’s net interest in its Louisiana properties, which net profits interest was granted to Wells Fargo, based on their relative fair market values at the date of issuance. The value assigned to the warrants of \$1,314,289 was recorded as an increase in additional paid-in capital and the value assigned to the net profits interest of \$213,148 was recorded as a credit to the full cost pool for oil and gas properties. The assignment of a value to the warrants and net profits interest resulted in a loan discount being recorded. The discount amortization is over the original three-year term of the debt as additional interest expense. Amortization for the years ended June 30, 2011, 2010 and 2009 was \$0, \$239,686 and \$514,620, respectively.

Cubic incurred loan costs of \$240,613 on the issuance of the debt and warrants. The amount allocable to the debt of \$166,590 has been capitalized and is being amortized over the term of the debt. Amortization for the years ended June 30, 2011, 2010 and 2009 was \$0, \$25,958 and \$55,733, respectively. Cubic also incurred commitment fees of \$170,000 related to subsequent increases in the Credit Facility’s borrowing base; such amount was capitalized in fiscal 2008 and is being amortized over the remaining term of the loan. Amortization for the years ended June 30, 2011, 2010 and 2009 was \$0, \$36,795 and \$79,001, respectively.

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CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

On December 18, 2009, the Company entered into a Second Amendment to Credit Agreement with Wells Fargo, providing for a revolving credit facility of up to \$40 million and a convertible term loan of \$5 million (the "Amended Credit Agreement"). The borrowing base under the revolving credit facility was initially established at \$25 million. The indebtedness bears interest at a fluctuating rate equal to the sum of the Wells Fargo Bank prime rate plus two percent (2%) per annum, matures on July 1, 2012 and is secured by substantially all of the assets of the Company. In connection with entering into the Amended Credit Agreement, the Company issued to Wells Fargo additional warrants, expiring on December 1, 2014, for the purchase of up to 5,000,000 shares of Company common stock currently at an exercise price of \$0.9911 per share, and extended the expiration date of the warrants to purchase 2,500,000 shares of Company common stock that were previously issued to Wells Fargo to December 1, 2014.

The Company allocated the proceeds from the issuance of the debt to the warrants, the debt and the beneficial conversion feature based on their fair market values at the date of issuance. The fair market value assigned to the extension of warrants to purchase 2,500,000 shares of Company common stock was \$923,302 and the value assigned to the issuance of the warrant to purchase the additional 5,000,000 shares of Company common stock was \$8,031,896, which was recorded as an increase in additional paid-in capital. The difference in the fair value of the term loan and the face amount of \$1,877,494 was recorded as an extinguishment of debt, offset by the amount of unamortized deferred loan cost and discounts associated with the original debt of \$129,871. The beneficial conversion feature equaled \$5,027,494, which was reduced to \$3,122,506 based on the limitation to the fair value to debt. The assignment of a value to the warrants and beneficial conversion feature as well as the write-down of the term loan to the fair value resulted in a total loan discount in the amount of \$13,955,198 being recorded. The discount is being amortized over the three-year term of the debt as additional interest expense. Amortization was \$5,500,699 for the year ended June 30, 2011 and was \$2,938,729 for the year ended June 30, 2010. Amortization for the fiscal year ending June 30, 2012 is expected to be approximately \$5,515,769.

In connection with the modification of the indebtedness, the Company recorded a gain on extinguishment of debt of \$1,747,623. Such amount includes the write-off of the unamortized deferred loan cost (\$26,947), and the write-off of the remaining loan discount (\$102,924).

Cubic incurred loan costs of \$50,000 on the issuance of the debt and warrants. The amount was capitalized and allocated to the debt and is being amortized over the term of the debt. Amortization was \$19,708 for the year ended June 30, 2011 and was \$10,529 for the year ended June 30, 2010. Amortization for the fiscal year ending June 30, 2012 is expected to be \$19,762.

On August 30, 2010, the Company entered into a Third Amendment to the Credit Agreement (the "Third Amendment") with Wells Fargo providing for an increase in the borrowing base for the Company's revolving credit facility from \$25 million to \$30 million. The Company borrowed the full amount of the increase in the borrowing base. The indebtedness under the credit facility, which includes the revolving credit facility and a

CUBIC ENERGY, INC.

NOTES TO CONDENSED FINANCIAL STATEMENTS

\$5 million convertible term loan, bears interest at a fluctuating rate equal to the sum of the Wells Fargo Bank prime rate plus two percent (2%) per annum, matures on July 1, 2012 and is secured by substantially all of the assets of the Company. In connection with entering into the Third Amendment, the Company issued to Wells Fargo additional warrants, expiring on December 1, 2014, for the purchase of up to 1,000,000 shares of the Company's common stock at an exercise price of \$1.00 per share. Loan costs of \$89,000 and loan discounts of \$527,430 were recognized.

The Company allocated the proceeds from the issuance of the debt to the warrants and the debt. The value assigned to the warrants of \$516,882 was recorded as an increase in additional paid-in-capital relating to common stock. The assignment of a value to the warrants resulted in a loan discount being recorded. The discount amortization is over the two-year term of the debt as additional interest expense. Amortization for the year ended June 30, 2011 was \$239,741. Amortization for the fiscal year ending June 30, 2012 is expected to be approximately \$287,689.

Cubic incurred loan costs of \$100,000 on the issuance of the debt and warrants. The amount allocable to the debt of \$89,451 has been capitalized and is being amortized over the term of the debt. Amortization for the year ended June 30, 2011 was \$40,660. Amortization for the fiscal year ending June 30, 2012 is expected to be approximately \$48,791.

May 2008 subordinated debt issue

On May 6, 2008, the Company issued a subordinated promissory note in the amount of \$2,000,000 (the "Subordinated Note") to Diversified Dynamics Corporation (the "Lender"), an entity controlled by William Bruggeman, a director who beneficially owns more than 5% of the common stock of the Company. The Subordinated Note bore interest at a fluctuating rate equal to the sum of the prime rate plus two percent (2%) per annum, and was scheduled to mature on April 30, 2010. As consideration for the loan made by the Lender pursuant to the Subordinated Note, the Company agreed to convey to the Lender, upon the repayment in full of the indebtedness evidenced by the Subordinated Note and the repayment in full of the senior indebtedness evidenced by the Credit Facility with Wells Fargo, an undivided 0.375% net profits interest in the future production of hydrocarbons from or attributable to Cubic's net interest in its Louisiana properties. The proceeds of the Subordinated Note were used for general corporate and working capital purposes.

On May 8, 2008, the Credit Facility with Wells Fargo was amended by the First Amendment to Credit Agreement (the "First Amendment"). Material provisions of the First Amendment included the following: (i) the Company may not prepay all or any part of the principal balance outstanding on the Term Loan prior to its maturity on July 1, 2012 without the consent of Wells Fargo; and (ii) the amount of the borrowing base was increased to \$20,000,000, which amount was fully drawn upon subsequent to the end of fiscal 2008, on August 20, 2008.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

December 2009 subordinated debt issue

On December 18, 2009, the Company issued a subordinated promissory note payable to Calvin A. Wallen, III, the Company's Chairman of the Board and Chief Executive Officer, in the principal amount of \$2,000,000 (the "Wallen Note"). This note bears interest at the prime rate plus one percent (1%), with interest payable monthly. The Wallen Note was entered into with the consent of Wells Fargo. The outstanding principal balance is due and payable on September 30, 2012 and is subordinated to all Wells Fargo indebtedness. The proceeds of the Wallen Note were used to repay the Subordinated Note. The net profits interest described above was conveyed to the Lender in connection with the repayment.

<u>Principal Amount Outstanding</u>	<u>as of June 30,</u>	
	<u>2011</u>	<u>2010</u>
Total long-term debt (including current portion)	\$ 37,000,000	\$ 32,000,000
Less current portion	-	-
Total long-term debt	<u>\$ 37,000,000</u>	<u>\$ 32,000,000</u>

Maturities of Debt

Fiscal 2012	\$ -
Fiscal 2013	37,000,000
Fiscal 2014 and thereafter	-

CUBIC ENERGY, INC.

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Note F – Related party transactions:

Effective January 1, 2002, the Company entered into an agreement with Tauren Exploration, Inc., an entity controlled by Cubic's Chairman of the Board, President and CEO that provides for the following:

- 1) As of January 1, 2002, the Company owed Tauren \$856,712, primarily comprised of non-interest bearing advances the Company had received over the course of several years. In exchange for the amounts owed to it, Tauren accepted the transfer of 856,712 newly issued shares of common stock in the Company that had a market price of \$0.70 per share.
- 2) The Company received the rights to participate in prospective oil and gas projects in which Tauren owns a working interest.
- 3) The Company shall, as requested, have the future privilege of using the general and administrative services of Tauren based on an agreed pro rata cost.
- 4) The Company issued three series of warrants to Tauren as described in Note C.

On December 1, 1997, as renewed and revised on January 1, 2002, the Company entered into a contract with Tauren to provide the necessary technical, administrative and management expertise needed to conduct its business. Tauren also paid various organization costs and consulting fees on behalf of the Company. The monthly amount charged to the Company was based on actual costs of materials and labor hours of Tauren that were used pursuant to the terms of the agreement. The agreement was terminated effective January 1, 2006, except as to the office sharing provisions, which were extended to June 30, 2007 and since continue on a month to month basis. The Company now has 10 employees and its offices are leased from Tauren. During fiscal 2011, the Company's only expense under the office sharing arrangement was the rent lease. The offices were leased on a month-to-month basis for an average monthly amount charged to the Company, from July 1, 2010 until December 31, 2010, of \$2,229. Effective, January 1, 2011, the Company signed a 2-year lease that charges the Company a monthly fee of \$8,000 per month, from an affiliate controlled by Mr. Wallen and the offices are owned by this affiliate. Charges to the Company under the contracts and subsequent arrangements were \$61,374, \$26,748 and \$26,748 for the fiscal years 2011, 2010 and 2009, respectively.

Tauren owns a working interest in the wells in which the Company owns a working interest. The Company owed \$14,537, \$78,679 and \$649,205 to Tauren for miscellaneous general and administrative expenses and royalties for fiscal 2011, 2010 and 2009, respectively. Tauren owed the Company \$5,127 for royalties paid by a third-party operator for fiscal year 2011 and \$0 for fiscal 2010 and 2009.

In addition, certain of the Company's working interests are operated by an affiliated company, Fossil Operating, Inc. ("Fossil"), which is owned 100% by the Company's President and Chief Executive Officer, Calvin A. Wallen III. At the end of fiscal years 2011, 2010 and 2009, the Company owed Fossil \$43,143, \$755,683 and \$815,239, respectively, for drilling costs and lease and operating expenses, and was owed by Fossil \$80,674, \$415,282 and \$271,615, respectively, for oil and gas sales.

On February 6, 2006, the Company entered into a Purchase Agreement with Tauren with respect to the purchase by the Company of certain Cotton Valley leasehold interests (approximately 11,000 gross acres; 5,000 net acres) held by Tauren. Pursuant to the Purchase Agreement, the Company acquired from Tauren a 35% working interest in approximately 2,400 acres and a 49% working interest in approximately 8,500 acres located in DeSoto and Caddo Parishes, Louisiana, along with an associated Area of Mutual Interest.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

and the right to acquire at "cost" (as defined in the Purchase Agreement) a seventy percent (70%) working interest in all additional mineral leases obtained by Tauren in the AMI, in exchange for (a) \$3,500,000 in cash, (b) 2,500,000 shares of Company common stock, (c) an unsecured 12.5% promissory note in the amount of \$1,300,000, which note was convertible into Company common stock at a conversion price of \$0.80 per share (the "Tauren Note"), and (d) a drilling credit of \$2,100,000. The Tauren Note was repaid on February 2, 2007.

The consideration described above was determined based upon negotiations between Tauren and a Special Committee of the Company's directors, excluding Mr. Wallen. The Special Committee obtained an opinion from its independent financial advisor with respect to the fairness, from a financial point of view, to the public stockholders of the Company, of such transactions.

On November 10, 2006, the maturity of the Tauren Note was extended to October 5, 2007. In connection with the extension of the Tauren Note, the Company issued to Tauren warrants, with three-year expirations, for the purchase of up to 50,000 shares of Company common stock at an exercise price of \$0.70 per share.

On February 2, 2007, the Tauren Note was retired pursuant to a provision in the note that required payment from the proceeds of an equity offering. The equity offering that occurred in December 2006 (see "Note C – Stockholders' Equity") was sufficient to facilitate such repayment.

On May 6, 2008, the Company issued a subordinated promissory note in the amount of \$2,000,000 to Diversified Dynamics Corporation, an entity controlled by William Bruggeman who, at the time of such transaction, was the beneficial owner of approximately 28.9% of the common stock of the Company. See "May 2008 subordinated debt issue" in "Note E – Long-term debt" elsewhere herein.

On November 24, 2009, the Company entered into transactions with Tauren and Langtry Mineral & Development, LLC ("Langtry"), both of which are entities controlled by Calvin Wallen III, the Chief Executive Officer of the Company, under which the Company acquired \$30,952,810 in pre-paid drilling credits (the "Drilling Credits") applicable towards the development of its Haynesville Shale rights in Northwest Louisiana. The Company expects to use the Drilling Credits to fund \$30,952,810 of its share of the drilling and completion costs for those horizontal Haynesville Shale wells drilled in sections previously operated by an affiliate of the Company, which are now operated by a third party. Any Drilling Credits not utilized by 2013 will be paid to Cubic, on a dollar for dollar basis.

As consideration for the Drilling Credits, the Company (a) conveyed to Tauren a net overriding royalty interest of approximately 2% in its leasehold rights below the Taylor Sand formation of the Cotton Valley and (b) on March 16, 2010 issued to Langtry 10,350,000 Company common shares and preferred stock with a stated value of \$10,350,000, convertible into Company common shares at \$1.20 per common share, with a five year conversion term. The preferred stock is entitled to cumulative dividends equal to 8% per annum, payable quarterly, which dividends may be paid in cash or in additional shares of preferred stock, in the Company's discretion. The preferred stock may be redeemed by the Company at any time, at a redemption price equal to 20% over the original issue price, plus accrued and unpaid dividends.

This transaction resulted in a reduction in the Company's oil and gas properties recorded cost in the amount of \$10,252,810.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

The consideration described above was determined based upon negotiations between Tauren and a Special Committee of the Company's directors, excluding Mr. Wallen. The Special Committee obtained an opinion from its independent financial advisor with respect to the fairness, from a financial point of view, to the public stockholders of the Company, of such transactions.

On December 18, 2009, the Company issued a subordinated promissory note payable to Mr. Wallen, in the principal amount of \$2,000,000 (the "Wallen Note"). This note bears interest at the prime rate plus one percent (1%), with interest payable monthly. The Wallen Note was entered into with the consent of Wells Fargo. The outstanding principal balance is due and payable on August 31, 2012 and is subordinated to all indebtedness to Wells Fargo. The proceeds of the Wallen Note were used to repay the Subordinated Note. The net profits interest described above was conveyed to the Lender in connection with the repayment.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Note G – Income taxes:

Deferred tax assets and liabilities are computed by applying the effective U.S. federal income tax rate to the gross amounts of temporary differences and other tax attributes. Deferred tax assets and liabilities relating to state income taxes are not material. 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. As of June 30, 2011, 2010 and 2009, the Company believed it was more likely than not that future tax benefits from net operating loss carryforwards and other deferred tax assets would not be realizable through generation of future taxable income; therefore, they were fully reserved.

The components of the net deferred federal income tax assets (liabilities) at June 30 were as follows:

	2011	2010	2009
Deferred tax assets:			
Net operating loss carryforwards	\$ 8,352,700	\$ 5,309,100	\$ 10,579,700
Depletion basis of assets and related accounts	-	1,842,900	2,309,800
Depreciation basis of assets	1,900	1,300	-
	\$ 8,354,600	\$ 7,153,300	\$ 12,889,500
Deferred tax liabilities:			
Depletion basis of assets and related accounts	\$ (785,200)	\$ -	\$ (1,200)
	\$ (785,200)	\$ -	\$ (1,200)
Net deferred tax (liabilities) assets before valuation allowance	\$ 7,569,400	\$ 7,153,300	\$ 12,888,300
Valuation allowance	(7,569,400)	(7,153,300)	(12,888,300)
Net deferred tax (liabilities) assets	\$ -	\$ -	\$ -

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

The following table summarizes the difference between the actual tax provision and the amounts obtained by applying the statutory tax rates to the income or loss before income taxes for the years ended June 30, 2011, 2010 and 2009:

	<u>2011</u>	<u>2010</u>	<u>2009</u>
Tax (benefit) calculated at statutory rate	\$ (2,572,000)	\$ (1,234,000)	\$ (6,191,000)
Losses not providing tax benefits	<u>2,572,000</u>	<u>1,234,000</u>	<u>6,191,000</u>
Current federal income tax provision (benefit)	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>
Change in valuation allowance	<u>\$ (416,100)</u>	<u>\$ 5,735,000</u>	<u>\$ -</u>

As of June 30, 2011, the Company had net operating loss carryforwards of approximately \$33,410,900, which are available to reduce future taxable income. These carryforwards expire as follows:

<u>Year</u>	<u>Net operating losses</u>
2028	\$ 10,389,100
2029	11,065,900
2031	<u>11,955,900</u>
	<u>\$ 33,410,900</u>

Note H – Commitments and contingencies:

Key personnel

The Company depends to a large extent on the services of Calvin A. Wallen III, the Company's President, Chairman of the Board, and Chief Executive Officer. The loss of the services of Mr. Wallen would have a material adverse effect on the Company's operations.

On February 29, 2008, the Company entered into employment agreements with Mr. Wallen and its Secretary, Jon S. Ross. The agreement with Mr. Wallen provides for a base salary of \$200,000 per year, while the agreement with Mr. Ross provides for a base salary of \$150,000 per year. The other terms and conditions of the agreements are substantially consistent.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Both agreements provide for a term of employment of 36 months from the effective date of February 1, 2008, which term shall be automatically extended by one additional month upon the expiration of each month during the term; provided, that the Company may terminate subsequent one-month extensions at any time. Each agreement is subject to early termination by the Company in the event that the employee dies, becomes totally disabled or commits an act constituting "Just Cause" under the agreement. The agreements provide that Just Cause includes, among other things, the conviction of certain crimes, habitual neglect of his duties to the Company or other material breaches by the employee of the agreement. Each agreement also provides that the employee shall be permitted to terminate his employment upon the occurrence of "Good Reason," as defined in the agreement. The agreements provide that Good Reason includes, among other things, a material diminution in the employee's authority, duties, responsibilities or salary, or the relocation of the Company's principal offices by more than 50 miles. If the employee's employment is terminated by (a) the Company other than due to the employee's death, disability or Just Cause, or (b) the employee for Good Reason, then the Company is required to pay all remaining salary through the end of the then-current term. The foregoing severance payment is subject to reduction under certain conditions.

On January 14, 2011, the Company entered into an employment agreement with its Chief Financial Officer, Larry G. Badgley. The agreement provides for the grant of stock options, under the Plan, for the purchase of an aggregate of 288,667 shares of Company common stock. These options have an exercise price \$1.20 per share and expire five years from their issue date. One option, for the purchase of 15,667 shares, was fully vested upon grant. The other option, for the purchase of 273,000 shares shall, subject to the other provisions of the option agreement, vest upon the earliest of: (a) immediately prior to a Change in Control (as defined in the Plan), (b) October 1, 2012, provided that Mr. Badgley's Continuous Service (as defined in the Plan) continues through October 1, 2012, (c) the termination by Mr. Badgley of his Continuous Service prior to October 1, 2012 in compliance with the terms of a then-effective written employment agreement between him and the Company or an affiliate of the Company or (d) the termination by the Company of Mr. Badgley's Continuous Service prior to October 1, 2012, other than for Just Cause (as defined in the employment agreement). We estimated the fair value of the options on the date of grant using the Black-Scholes valuation model to be \$100,997.

Environmental matters

The Company's operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling and transportation of oil and gas and the discharge of materials into the environment. The Company generates typical oil and gas field wastes, including hazardous wastes that are subject to the federal Resources Conservation and Recovery Act and comparable state statutes. Furthermore, certain wastes generated by the Company's oil and gas operations that are currently exempt from regulation as "hazardous wastes" may in the

future be designated as "hazardous wastes" and therefore be subject to more rigorous and costly operating and disposal requirements. All of the Company's properties are operated by third parties over whom the Company has limited control. In addition to the Company's lack of control over properties operated by others, the failure of previous owners or operators to comply with applicable environmental regulations may, in certain circumstances, adversely impact the Company.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Office Lease

Effective, January 1, 2011, the Company signed a 2 year lease that charges the Company a monthly fee of \$8,000 per month. The Company believes that there is other appropriate space available in the event the Company should terminate its current leasing arrangement, though the Company believes the monthly rental fee would likely exceed \$8000 per month. Rental expense was \$61,374, 26,748 and \$26,748 for fiscal years 2011, 2010 and 2009, respectively. Future minimum lease payments under operating lease are \$96,000 and \$48,000 for years ending June 30, 2012 and 2013, respectively.

Legal proceedings

The Company is facing a lawsuit from one mineral owner, Gloria's Ranch, LLC that would have a material effect on the acreage position of the Company if ultimately adjudicated entirely in favor of the mineral owner. The Company believes it will prevail regarding a majority, if not all, of the acreage at issue in the Gloria's Ranch lawsuit.

On May 18, 2011, EXCO and BG informed the Company that they do not intend to honor the balance of the Drilling Credits, which was approximately \$18 million at that time. The Company believes that there is no valid basis to dispute the remaining balance of the Drilling Credits. This dispute was submitted to mediation on August 26, 2011, but was not resolved. The Company has submitted this dispute to binding arbitration, and has filed a court action in District Court in Dallas County, Texas to compel such arbitration. The Company intends to continue to vigorously defend its rights to the remaining balance of the Drilling Credits. If the Company is not successful in defending its rights, it expects to fund its share of expenses from wells drilled by EXCO and BG through one of the other sources of funds described above.

Management believes we will prevail, but if not, we have the option of going "non-consent" or being deemed non-consent on current and future horizontal Haynesville Shale wells operated by EXCO and BG. By being deemed to be non-consent, in addition to penalties we would reduce our share of revenues from these wells, we would be required to pay the royalty owners their share of revenues, which we anticipate to be up to approximately \$65,000 per well per month, or an aggregate of approximately \$590,000 based on the current number of EXCO and BG operated wells for the balance of fiscal 2012. Other than this \$590,000, we do not expect any additional royalties to be paid out of pocket by Cubic during fiscal 2012, with respect to EXCO and BG operated wells. With future strategies to obtain additional financing, funds generated through existing wells and cash on hand, we expect to be able to continue to pay our expenses as they come due. It is possible that EXCO and BG exhaust the remaining balance of the Drilling Credits during fiscal 2012. The balance of the Drilling Credits not exhausted is due and payable in cash early in fiscal 2013.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Note I - Cost of oil and gas properties:

Costs incurred

Costs (capitalized and expensed) incurred in oil and gas property acquisition, exploration, and development activities for the years ended June 30, 2011, 2010 and 2009 were as follows:

	<u>2011</u>	<u>2010</u>	<u>2009</u>
Property acquisitions	\$ 448,432	\$ 1,777,848	\$ 72,385
Exploration	-	-	5,928,825
Development	<u>10,175,986</u>	<u>6,988,115</u>	<u>-</u>
	<u>\$10,624,418</u>	<u>\$ 8,765,963</u>	<u>\$ 6,001,210</u>

Capitalized costs

The aggregate amounts of capitalized costs relating to oil and gas producing activities and the aggregate amounts of the related accumulated depreciation, depletion, and amortization at June 30, 2011, 2010 and 2009 were as follows:

	<u>2011</u>	<u>2010</u>	<u>2009</u>
Proved properties	\$ 47,788,575	\$ 37,033,711	\$ 37,907,410
Unproved properties	-	130,446	890,715
	<u>47,788,575</u>	<u>37,164,157</u>	<u>38,798,125</u>
Less: accumulated depreciation, depletion and amortization of oil and gas properties	<u>9,774,375</u>	<u>6,071,190</u>	<u>4,923,318</u>
Total properties	<u>38,014,200</u>	<u>31,092,967</u>	<u>33,874,807</u>
Less: accumulated impairment of oil and gas properties due to full cost ceiling test	<u>(22,181,701)</u>	<u>(22,181,701)</u>	<u>(22,181,701)</u>
Net properties	<u>\$ 15,832,499</u>	<u>\$ 8,911,266</u>	<u>\$ 11,693,106</u>

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Results of operations

The results of operations from oil and gas producing activities for the years ended June 30, 2011, 2010 and 2009 were as follows:

	<u>2011</u>	<u>2010</u>	<u>2009</u>
Revenues:			
Revenues	\$ 6,133,299	\$ 3,486,171	\$ 1,858,139
Preferred return	-	-	-
	<u>6,133,299</u>	<u>3,486,171</u>	<u>1,858,139</u>
Expenses (excluding G&A and interest expense):			
Production, operating and development costs	1,857,528	1,845,153	1,372,041
Depreciation, depletion and amortization	3,707,255	1,147,873	771,861
Impairment loss on oil and gas properties	-	-	20,390,819
	<u>5,564,783</u>	<u>2,993,026</u>	<u>(22,534,721)</u>
Results before income taxes	568,516	493,145	(20,676,582)
Provision for income taxes	-	-	-
Results of operations (excluding corporate overhead and interest expense)	<u>\$ 568,516</u>	<u>\$ 493,145</u>	<u>\$ (20,676,582)</u>

Note J - Oil and gas reserves information (unaudited):

The estimates of proved oil and gas reserves utilized in the preparation of the financial statements are estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year-end except by contractual arrangements.

The Company emphasizes that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. The Company's policy is to amortize capitalized oil and gas costs on the unit of production method, based upon these reserve estimates. The amortization was \$2.48 per Mcf during the twelve month period ended June 30, 2011, as compared to \$1.43 per Mcf and \$2.55 per Mcf during the same periods in 2010 and 2009, respectively. It is reasonably possible that, because of changes in market conditions or the inherent imprecision of these reserve estimates, that the estimates of future cash inflows, future gross revenues, the amount of oil and gas reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term.

If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

The following unaudited table sets forth proved oil and gas reserves, all within the United States, at June 30, 2011, 2010 and 2009 together with the changes therein:

	Natural Gas (Mcfs)		
	2011	2010	2009
Proved developed and undeveloped reserves:			
Beginning of year	29,157,280	20,319,627	6,089,729
Revisions of previous estimates	(2,429,214)	1,399,599	5,233,858
Extensions and discoveries	32,445,450	8,838,950	9,275,556
Production	(1,481,430)	(792,433)	(279,516)
Disposals of reserves in place	-	(608,463)	-
End of year	<u>57,692,086</u>	<u>29,157,280</u>	<u>20,319,627</u>
Proved developed & undeveloped reserves, end of year	<u>57,692,086</u>	<u>29,157,280</u>	<u>20,319,627</u>
	Oil, Condensate, Ngl (Bbls)		
	2011	2010	2009
Proved developed and undeveloped reserves:			
Beginning of year	8,647	126,209	88,948
Revisions of previous estimates	(4,742)	(112,547)	(8,917)
Extensions and discoveries	-	1,038	49,711
Production	(2,706)	(2,279)	(3,533)
Disposals of reserves in place	-	(3,774)	-
End of year	<u>1,199</u>	<u>8,647</u>	<u>126,209</u>
Proved developed & undeveloped reserves, end of year	<u>1,199</u>	<u>8,647</u>	<u>126,209</u>
	Natural Gas (Mcfs)		
	2011	2010	2009
Proved developed reserves:			
Beginning of year	2,666,610	337,993	1,019,276
End of year	6,634,236	2,666,610	337,993
Proved undeveloped reserves:			
Beginning of year	26,490,670	19,981,634	5,070,453
End of year	51,057,850	26,490,670	19,981,634
	Oil, Condensate, Ngl (Bbls)		
	2011	2010	2009
Proved developed reserves:			
Beginning of year	1,166	2,968	23,645
End of year	1,199	1,166	2,968
Proved undeveloped reserves:			
Beginning of year	7,481	123,241	65,303
End of year	-	7,481	123,241

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

The majority of the Company's Louisiana acreage lies atop the center of what is known in our industry as the "Haynesville Shale Play" (which we refer to as the "Bossier/Haynesville shale" elsewhere herein), one of the most prolific field discoveries in the United States. The discovery of the existence of the Bossier/Haynesville shale formations in the Company's acreage in fiscal 2008 led to a shift in strategy away from concentrating solely on the development of the Cotton Valley and other shallow formations in our Bethany Longstreet and Johnson Branch fields, and to commencement of the development of the Bossier/Haynesville shale acreage. Development slowed in fiscal 2009, due to deteriorated economic conditions, a harsh debt and equity environment, stubbornly high field operation costs, and collapse in the pricing of natural gas.

The strategic transactions consummated by the Company in the first half of fiscal 2010 repositioned the Company for increased development of its acreage. And, development activity did gain some momentum by the second half of fiscal 2010, with increased activity undertaken by EXCO as well as other third party Operators. Though not at expected levels, this increase in activity continued through fiscal 2011. While depressed pricing for natural gas persisted through fiscal 2011, the Company was able to benefit from the increased activity that commenced in the second half of fiscal 2010 through fiscal 2011.

The "Revisions of previous estimates" amount of (2,429,214) Mcf in fiscal 2011 was primarily a result of more performance information being available for the fiscal 2011 reserve report. Based on updated performance rates and lower natural gas prices, downward revisions of an aggregate of 490,044 Mcf were made to the proved developed reserves of our Bossier/Haynesville shale horizontal wells and our Cotton Valley vertical wells. A downward revision of an aggregate of 1,939,170 Mcf was recognized for certain sections in which the Company maintains a working interest stemming from pre-existing proved undeveloped offset locations, resulting from the proximity to a competitor's productive horizontally-drilled Haynesville Shale wells.

The "Extensions and discoveries" amount of 32,445,450 Mcf in fiscal 2011 was primarily due to new proved undeveloped offset locations in which the Company maintains a working interest based upon the ability to utilize 160 acre spacing per Unit for horizontally-drilled Haynesville Shale wells. In fiscal 2010, with the exception of a few Units, the Company utilized 640 acre spacing per Unit for horizontally-drilled Haynesville Sale wells. This amount was also due to a much lesser extent as a result of exploratory and developmental, or "step out", drilling in our Johnson Branch acreage in fiscal 2011. The reserve estimates attributable to these new proved undeveloped locations are listed under "Extensions and discoveries."

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Standardized measure of discounted future net cash flows relating to proved reserves:

The Standardized Measure of discounted future net cash flows (discounted at 10%) from production of proved reserves was developed as follows:

- An estimate was made of the quantity of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.
- In accordance with SEC guidelines, the engineers' estimates of future net revenues from our proved properties and the present value thereof for fiscal 2011 are made using the twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Prior year estimates were not required to be restated and reflect previously disclosed estimates using year-end prices. These prices are held constant throughout the life of the properties. Oil and natural gas prices are adjusted for each lease for quality, contractual agreements, lease use shrinkage and regional price variations.
- The future gross revenue streams were reduced by estimated future operating costs (including production and ad valorem taxes) and future development and abandonment costs, all of which were based on current costs in effect at June 30 of the year presented and held constant throughout the life of the properties.
- Future income taxes were calculated by applying the statutory federal and state income tax rate to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations.

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

The resulting future net cash flows were discounted using a rate of 10% per annum (Table 1). The standardized measure of discounted net cash flow amounts contained in the following tabulation does not purport to represent the fair market value of the Company's oil and gas proved by drilling or production history. There are significant uncertainties inherent in estimating timing and amount of future costs. In addition, the method of valuation utilized is based on current prices and costs and the use of a 10% discount rate, and is not necessarily appropriate for determining fair value (Table 2).

The following is the estimated standardized measure relating to proved oil and gas reserves at June 30, 2011, 2010 and 2009:

Table 1	2011	2010	2009
Future cash flows	\$ 261,446,375	\$ 148,560,880	\$ 80,937,110
Future production costs	(43,345,400)	(22,826,320)	(9,382,262)
Future development costs	(126,835,250)	(32,813,060)	(38,888,060)
Future severance tax expense	(4,330,356)	(2,184,380)	(5,850,567)
Future income taxes	-	-	-
Future net cash flows	<u>\$ 86,935,369</u>	<u>\$ 90,737,120</u>	<u>\$ 26,816,221</u>
Ten percent annual discount for estimated timing of net cash flows	<u>(40,024,625)</u>	<u>(25,979,830)</u>	<u>(16,013,831)</u>
Standardized measure of discounted future net cash flows	<u><u>\$ 46,910,744</u></u>	<u><u>\$ 64,757,290</u></u>	<u><u>\$ 10,802,390</u></u>

The following is an analysis of changes in the estimated standardized measure of proved reserves during the years ended June 30, 2011, 2010 and 2009:

Table 2	2011	2010	2009
Changes from:			
Sale of oil and gas produced	\$ (4,275,771)	\$ (1,641,018)	\$ (486,098)
Net changes in prices and production costs	(12,465,909)	8,664,461	(46,382,115)
Extensions and discoveries	19,367,520	16,205,860	4,501,970
Revision of previous quantity estimates	(6,450,989)	1,236,952	15,167,786
Accretion of discounts	6,475,729	1,080,239	3,311,066
Net change in income taxes	(2,178,009)	(324,157)	-
Disposals of reserves in place	-	(906,387)	-
Development costs incurred that reduced future development costs	(321,688)	(1,597,267)	-
Changes in future development costs	(604,579)	(330,545)	7,536,184
Changes in timing of production and other	(17,392,850)	31,566,762	(5,957,059)
Change in standardized measure	<u><u>\$ (17,846,546)</u></u>	<u><u>\$ 53,954,900</u></u>	<u><u>\$ (22,308,266)</u></u>

CUBIC ENERGY, INC.

NOTES TO FINANCIAL STATEMENTS

Note K – Selected quarterly financial data (unaudited):

Summarized unaudited quarterly financial data for fiscal 2011 and 2010 are as follows:

	<u>First Quarter</u>	<u>Second Quarter</u>	<u>Third Quarter</u>	<u>Fourth Quarter</u>	<u>Total</u>
Fiscal 2011					
Revenues	\$ 839,824	\$ 1,343,798	\$ 2,261,227	\$ 1,688,450	\$ 6,133,299
Loss before income taxes	\$ (2,069,167)	\$ (2,273,351)	\$ (2,518,318)	\$ (3,428,400)	\$ (10,289,236)
Net loss	\$ (2,069,167)	\$ (2,273,351)	\$ (2,518,318)	\$ (3,428,400)	\$ (10,289,236)
Net loss available to common shareholders	\$ (2,277,867)	\$ (2,482,051)	\$ (2,722,419)	\$ (3,667,654)	\$ (11,149,991)
Net loss per common share - basic and diluted (1)	<u>\$ (0.03)</u>	<u>\$ (0.03)</u>	<u>\$ (0.04)</u>	<u>\$ (0.05)</u>	<u>\$ (0.15)</u>
Weighted average common shares outstanding	75,394,579	75,397,019	76,608,699	76,815,908	76,048,925
Fiscal 2010					
Revenues	\$ 359,901	\$ 599,117	\$ 898,075	\$ 1,629,078	\$ 3,486,171
Loss before income taxes	\$ (1,129,853)	\$ 454,486	\$ (2,624,315)	\$ (1,636,943)	\$ (4,936,625)
Net loss	\$ (1,129,853)	\$ 454,486	\$ (2,624,315)	\$ (1,636,943)	\$ (4,936,625)
Net loss available to common shareholders	\$ (1,129,853)	\$ 454,486	\$ (2,624,315)	\$ (1,876,943)	\$ (5,176,625)
Net loss per common share - basic and diluted (1)	<u>\$ (0.02)</u>	<u>\$ 0.01</u>	<u>\$ (0.04)</u>	<u>\$ (0.03)</u>	<u>\$ (0.08)</u>
Weighted average common shares outstanding	63,551,697	64,674,565	66,781,797	75,394,579	67,583,793

(1) The sum of the per share amounts per quarter does not equal the total year amount due to changes in the weighted average number of common shares outstanding in each quarter.

Note L – Subsequent Events

On July 28, 2011, the Board of Directors for the Company unanimously agreed to pay the July 1, 2011 dividend to Langtry Mineral & Development, LLC (“Langtry”) fifty percent (50%) in Series A preferred shares and fifty percent (50%) in cash; and unanimously authorized the issuance of 1077 Series A preferred shares and \$107,751 in cash. The Board of Directors also agreed to the issuance of 55 preferred shares and \$18,138 in cash for previously unpaid dividends. This brings the total preferred shares outstanding to 109,123, as of September 9, 2011.

EXHIBIT INDEX

<u>No.</u>	<u>Description</u>
3.1	Amended and Restated Certificate of Formation (incorporated by reference to Exhibit 3.1 to the Registrant's Form 8-K filed with the SEC on March 10, 2010).
3.2	Certificate of Designation (incorporated by reference to Exhibit 3.2 to Registrant's Form 8-k filed with the SEC on March 10, 2010).
3.3	Bylaws (incorporated by reference to Exhibit 3.2 of the Company's Form 10-KSB for the period ended June 30, 2000).
10.1	Subscription and Registration Rights Agreement with George Karfunkel, dated July 26, 2006 (filed as Exhibit 10.1 to the Company's Form 8-K dated July 28, 2006).
10.2	Subscription and Registration Rights Agreement with Yehuda Neuberger and Anne Neuberger JTWROS dated July 26, 2006 (filed as Exhibit 10.2 to the Company's Form 8-K dated July 28, 2006).
10.3	Warrant issued to Yehuda Neuberger and Anne Neuberger JTWROS (filed as Exhibit 10.4 to the Company's Form 8-K dated July 28, 2006).
10.4	Form of Subscription and Registration Rights Agreement (filed as Exhibit 10.1 to the Company's Form 8-K filed December 21, 2006).
10.5	Form of Warrant (filed as Exhibit 10.2 to the Company's Form 8-K filed December 21, 2006).
10.6	Credit Agreement dated March 5, 2007 by and between Cubic Energy, Inc. and Wells Fargo Capital, Inc. (filed as Exhibit 10.1 to the Company's Form 8-K filed March 9, 2007).
10.7	Warrant to Purchase Shares of Common Stock of Cubic Energy, Inc. dated March 5, 2007, issued to Wells Fargo Energy Capital, Inc. (filed as Exhibit 10.4 to the Company's Form 8-K on March 9, 2007).
10.8	Form of Assignment of Net Profits Interest (filed as Exhibit 10.6 to the Company's Form 8-K on March 9, 2007).
10.9	Employment Agreement with Calvin A. Wallen, III, dated February 29, 2008 (filed as Exhibit 10.1 to the Company's Form 8-K on March 5, 2008) **.
10.10	Employment Agreement with Jon S. Ross dated February 29, 2008 (filed as Exhibit 10.1 to the Company's Form 8-K on March 5, 2008) **.
10.11	First Amendment to Credit Agreement with Wells Fargo Energy Capital dated May 8, 2008 (filed as Exhibit 10.2 to the Company's Form 10-QSB for the quarter ended March 31, 2008).
10.12	Form of Subscription and Registration Rights Agreement (filed as Exhibit 10.1 to the Company's Form 8-K filed September 1, 2009).

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- 10.13 Form of Warrant (filed as Exhibit 10.2 to the Company's Form 8-K filed September 1, 2009).
- 10.14 Purchase and Sale Agreement (Cubic Override) dated November 24, 2009 between the Company and Tauren Exploration, Inc. (filed as Exhibit 10.1 to the Company's Form 8-K filed December 1, 2009)
- 10.15 Purchase and Sale Agreement (Langtry Override) dated November 24, 2009 between the Company and Langtry Mineral & Development, LLC (filed as Exhibit 10.2 to the Company's Form 8-K filed December 1, 2009)
- 10.16 Subscription and Common Stock Purchase Agreement dated November 24, 2009 between the Company and Langtry Mineral & Development, LLC (filed as Exhibit 10.3 to the Company's Form 8-K filed December 1, 2009)
- 10.17 Subscription and Preferred Stock Purchase Agreement dated November 24, 2009 between the Company and Langtry Mineral & Development, LLC (filed as Exhibit 10.4 to the Company's Form 8-K filed December 1, 2009)
- 10.18 Second Amendment to Credit Agreement, dated December 18, 2009, by and between Cubic Energy, Inc. and Wells Fargo Energy Capital, Inc. (filed as Exhibit 10.1 to the Company's Form 8-K filed December 23, 2009)
- 10.19 Promissory Note, dated as of December 18, 2009, by Cubic Energy, Inc., payable to Wells Fargo Energy Capital, Inc. in the maximum principal amount of \$40,000,000 (filed as Exhibit 10.2 to the Company's Form 8-K filed December 23, 2009)
- 10.20 Convertible Promissory Note, dated as of December 18, 2009, by Cubic Energy, Inc., payable to Wells Fargo Energy Capital, Inc. in the principal amount of \$5,000,000 (filed as Exhibit 10.3 to the Company's Form 8-K filed December 23, 2009)
- 10.21 Amended and Restated Warrant to Purchase Shares of Common Stock of Cubic Energy, Inc., dated December 18, 2009, issued to Wells Fargo Energy Capital, Inc. (filed as Exhibit 10.4 to the Company's Form 8-K filed December 23, 2009)
- 10.22 Warrant to Purchase Shares of Common Stock of Cubic Energy, Inc., dated December 18, 2009, issued to Wells Fargo Energy Capital, Inc. (filed as Exhibit 10.5 to the Company's Form 8-K filed December 23, 2009)
- 10.23 Amended and Restated Registration Rights Agreement, dated as of December 18, 2009, by and between Cubic Energy, Inc. and Wells Fargo Energy Capital, Inc. (filed as Exhibit 10.6 to the Company's Form 8-K filed December 23, 2009)
- 10.24 Subordinated Promissory Note, dated as of December 18, 2009, by Cubic Energy, Inc., payable to Calvin A. Wallen, III (filed as Exhibit 10.7 to the Company's Form 8-K filed December 23, 2009)
- 10.25 Third Amendment to Credit Agreement, dated August 30, 2010, by and between Cubic Energy, Inc. and Wells Fargo Energy Capital, Inc. (filed as Exhibit 10.1 to the Company's Form 8-K filed September 1, 2010)
- 10.26 Warrant to Purchase Shares of Common Stock of Cubic Energy, Inc., dated August 30, 2010, issued to Wells Fargo Energy Capital, Inc. (filed as Exhibit 10.2 to the Company's Form 8-K

filed September 1, 2010)

- 10.27 Second Amended and Restated Registration Rights Agreement, dated as of August 30, 2010, by and between Cubic Energy, Inc. and Wells Fargo Energy Capital, Inc. (filed as Exhibit 10.3 to the Company's Form 8-K filed September 1, 2010)
- 10.28 Cubic Energy, Inc. 2005 Stock Option Plan (filed as Exhibit D to the Company's Definitive Schedule 14A filed with the SEC on December 12, 2005) **
- 10.29 Amendment to Cubic Energy, Inc. 2005 Stock Option Agreement effective as of May 7, 2010 (filed as Exhibit 10.37 to the Company's Form 10-K filed September 28, 2010) **
- 10.30 Employment Agreement with Larry G. Badgley, dated January 14, 2011 (filed as Exhibit 10.1 to the Company's Form 8-K on January 18, 2011) **
- 23.1* Consent of Philip Vogel & Co., PC
- 23.2* Consent of RPS
- 31.1* Rule 13a-14(a)/15d-14(a) Certification of Calvin A. Wallen, III
- 31.2* Rule 13a-14(a)/15d-14(a) Certification of Larry G. Badgley
- 32.1* Section 1350 Certification of Calvin A. Wallen, III
- 32.2* Section 1350 Certification of Larry G. Badgley
- 99.1* RPS Reserve Report summary letter

* Filed herewith.

** Management Compensation Contracts

Exhibit 31.1

CERTIFICATION

Pursuant to Rule 13a-14(a) and 15d-14(a)

I, Calvin A. Wallen, III, certify that:

1. I have reviewed this annual report on Form 10-K of Cubic Energy, Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report.
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report.
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of the registrant's Board of Directors (or persons performing the equivalent function):
 - (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: September 28, 2011

Signature: /s/ Calvin A. Wallen, III
Calvin A. Wallen, III, C.E.O.

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Exhibit 31.2

CERTIFICATION Pursuant to Rule 13a-14(a) and 15d-14(a)

I, Larry G. Badgley, certify that:

1. I have reviewed this annual report on Form 10-K of Cubic Energy, Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report.
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report.
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of the registrant's Board of Directors (or persons performing the equivalent function):
 - (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: September 28, 2011

Signature: /s/ Larry G. Badgley
Larry G. Badgley, C.F.O.

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Exhibit 32.1

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Cubic Energy, Inc. (the “Company”) on Form 10-K for the period ending June 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, as C.E.O., certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: September 28, 2011

Signature: /s/ Calvin A. Wallen, III
Calvin A. Wallen, III, C.E.O.

Exhibit 32.2

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Cubic Energy, Inc. (the “Company”) on Form 10-K for the period ending June 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, as C.F.O., certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: September 28, 2011

Signature: /s/ Larry G. Badgley
Larry G. Badgley, C.F.O.