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

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended June 30, 2011

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 001-16317

CONTANGO OIL & GAS COMPANY

(Exact name of registrant as specified in its charter)

Delaware	**95-4079863**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

3700 Buffalo Speedway, Suite 960
Houston, Texas 77098
(Address of principal executive offices)

(713) 960-1901
(Registrant's telephone number, including area code)

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

Common Stock, Par Value $0.04 per share	NYSE Amex

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ] No [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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [ ] No [ ]

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

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]
(Do not check if smaller reporting company)

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

At December 31, 2010, the aggregate market value of the registrant's common stock held by non-affiliates (based upon the closing sale price of shares of such common stock as reported on the NYSE Amex was $738,538,390. As of August 26, 2011, there were 15,627,966 shares of the registrant's common stock outstanding.

Documents Incorporated by Reference

Items 10, 11, 12, 13 and 14 of Part III have been omitted from this report since registrant will file with the Securities and Exchange Commission, not later than 120 days after the close of its fiscal year, a definitive proxy statement, pursuant to Regulation 14A. The information required by Items 10, 11, 12, 13 and 14 of this report, which will appear in the definitive proxy statement, is incorporated by reference into this Form 10-K.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR ENDED JUNE 30, 2011

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PART III

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Some of the statements made in this report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, and Section 21E of the Securities Exchange Act of 1934, as amended. The words and phrases "should be", "will be", "believe", "expect", "anticipate", "estimate", "forecast", "goal" and similar expressions identify forward-looking statements and express our expectations about future events. These include such matters as:

- Our financial position
- Business strategy, including outsourcing
- Meeting our forecasts and budgets
- Anticipated capital expenditures
- Drilling of wells
- Natural gas and oil production and reserves
- Timing and amount of future discoveries (if any) and production of natural gas and oil
- Operating costs and other expenses
- Cash flow and anticipated liquidity
- Prospect development
- Property acquisitions and sales
- New governmental laws and regulations
- Expectations regarding oil and gas markets in the United States

Although we believe the expectations reflected in such forward-looking statements are reasonable, such expectations may not occur. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from actual future results expressed or implied by the forward-looking statements. These factors include among others:

- Low and/or declining prices for natural gas and oil
- Natural gas and oil price volatility
- Operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and gas processing facilities
- The risks associated with acting as the operator in drilling deep high pressure and temperature wells in the Gulf of Mexico
- The risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which the Company has made a large capital commitment relative to the size of the Company's capitalization structure
- The timing and successful drilling and completion of natural gas and oil wells
- Availability of capital and the ability to repay indebtedness when due
- Availability of rigs and other operating equipment
- Ability to raise capital to fund capital expenditures
- Timely and full receipt of sale proceeds from the sale of our production
- The ability to find, acquire, market, develop and produce new natural gas and oil properties
- Interest rate volatility
- Uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures
- Operating hazards attendant to the natural gas and oil business
- Downhole drilling and completion risks that are generally not recoverable from third parties or insurance
- Potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps
- Weather
- Availability and cost of material and equipment
- Delays in anticipated start-up dates
- Actions or inactions of third-party operators of our properties
- Actions or inactions of third-party operators of pipelines or processing facilities
- The ability to find and retain skilled personnel
- Strength and financial resources of competitors
- Federal and state regulatory developments and approvals
- Environmental risks
- Worldwide economic conditions

- The ability to construct and operate offshore infrastructure, including pipeline and production facilities
- The continued compliance by the Company with various pipeline and gas processing plant specifications for the gas and condensate produced by the Company
- Drilling and operating costs, production rates and ultimate reserve recoveries in our Eugene Island 10 (“Dutch”) and State of Louisiana (“Mary Rose”) acreage
- Restrictions on permitting activities
- Expanded rigorous monitoring and testing requirements
- Legislation that may regulate drilling activities and increase or remove liability caps for claims of damages from oil spills
- Ability to obtain insurance coverage on commercially reasonable terms
- Accidental spills, blowouts and pipeline ruptures
- Impact of new and potential legislative and regulatory changes on Gulf of Mexico operating and safety standards

You should not unduly rely on these forward-looking statements in this report, as they speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly release any revisions to these forward-looking statements to reflect events or circumstances occurring after the date of this report or to reflect the occurrence of unanticipated events. See the information under the heading “Risk Factors” referred to on page 13 of this report for some of the important factors that could affect our financial performance or could cause actual results to differ materially from estimates contained in forward-looking statements.

All references in this Form 10-K to the "Company", "Contango", "we", "us" or "our" are to Contango Oil & Gas Company and wholly-owned Subsidiaries. Unless otherwise noted, all information in this Form 10-K relating to natural gas and oil reserves and the estimated future net cash flows attributable to those reserves are based on estimates prepared by independent engineers and are net to our interest.

PART I

Item 1. *Business*

Overview

Contango is a Houston-based, independent natural gas and oil company. The Company's core business is to explore, develop, produce and acquire natural gas and oil properties primarily offshore in the Gulf of Mexico in water-depths of less than 300 feet. Contango Operators, Inc. ("COI"), our wholly-owned subsidiary, acts as operator on our offshore prospects.

Our Strategy

Our exploration strategy is predicated upon two core beliefs: (1) that the only competitive advantage in the commodity-based natural gas and oil business is to be among the lowest cost producers and (2) that virtually all the exploration and production industry's value creation occurs through the drilling of successful exploratory wells. As a result, our business strategy includes the following elements:

Funding exploration prospects generated by Juneau Exploration, L.P., our alliance partner. We depend primarily upon our alliance partner, Juneau Exploration, L.P. ("JEX"), for prospect generation expertise. JEX is experienced and has a successful track record in exploration.

Using our limited capital availability to increase our reward/risk potential on selective prospects. We have concentrated our risk investment capital in our offshore Gulf of Mexico prospects. Exploration prospects are inherently risky as they require large amounts of capital with no guarantee of success. COI drills and operates our offshore prospects. Should we be successful in any of our offshore prospects, we will have the opportunity to spend significantly more capital to complete development and bring the discovery to producing status.

Sale of proved properties. From time-to-time as part of our business strategy, we have sold and in the future expect to continue to sell some or a substantial portion of our proved reserves and assets to capture current value, using the sales proceeds to further our offshore exploration activities. Since its inception, the Company has sold approximately $524 million worth of natural gas and oil properties, and views periodic reserve sales as an opportunity to capture value, reduce reserve and price risk, and as a source of funds for potentially higher rate of return natural gas and oil exploration opportunities.

Controlling general and administrative and geological and geophysical costs. Our goal is to be among the most efficient in the industry in revenue and profit per employee and among the lowest in general and administrative costs. We have eight employees. We plan to continue outsourcing our geological, geophysical, and reservoir engineering and land functions, and partnering with cost efficient operators.

Structuring incentives to drive behavior. We believe that equity ownership aligns the interests of our employees and stockholders. Our directors and executive officers beneficially own or have voting control over approximately 17% of our common stock.

Contango Operators, Inc.

COI, a wholly-owned subsidiary of the Company, drills, and operates our wells in the Gulf of Mexico, as well as attends lease sales and acquires leasehold acreage. Additionally, COI may acquire significant working interests in offshore exploration and development opportunities in the Gulf of Mexico, under farm-out agreements, or similar agreements, with Republic Exploration, LLC ("REX"), JEX and/or third parties.

The Company's offshore production consists of 11 wells located on federal and State of Louisiana leases in the shallow waters of the Gulf of Mexico. These 11 wells produce via the following three platforms:

Eugene Island 11 Platform

As of August 22, 2011, the Company-owned and operated platform at Eugene Island 11 was processing approximately 46.6 million cubic feet equivalent per day ("Mmcfed"), net to Contango. This platform was designed with a capacity of 500 million cubic feet per day ("Mmcfd") and 6,000 barrels of oil per day ("bopd"). In September 2010 the Company completed installing a companion platform and two pipelines adjacent to the Eugene Island 11 platform to be able to access alternate markets. These platforms service production from the Company's four Mary Rose wells and Eloise North well, which are all located in State of Louisiana waters, as well as our Dutch #4 well and Dutch #5 well (previously Eloise South) (See "Other Activities" below), which are both located in federal waters. From these platforms, we flow the majority of our gas to an American Midstream pipeline via our 8" pipeline, which has been designed with a capacity of 80 Mmcfd, and from there to a third-party owned and operated on-shore processing facility at Burns Point, Louisiana. We flow our condensate via an ExxonMobil pipeline to on-shore markets and multiple refineries.

Alternatively, our gas and condensate can flow to our Eugene Island 63 auxiliary platform via our 20" pipeline, which has been designed with a capacity of 330 Mmcfd and 6,000 bopd, and from there to third-party owned and operated on-shore processing facilities near Patterson, Louisiana, via an ANR pipeline.

Eugene Island 24 Platform

As of August 22, 2011, this third-party owned and operated production platform at Eugene Island 24 was processing approximately 24.6 Mmcfed, net to Contango. This platform was designed with a capacity of 100 Mmcfd and 3,000 bopd. This platform services production from the Company's Dutch #1, #2 and #3 federal wells. From this platform, the gas flows through an American Midstream pipeline into a third-party owned and operated on-shore processing facility at Burns Point, Louisiana, and the condensate flows via an ExxonMobil pipeline to on-shore markets and multiple refineries.

Ship Shoal 263 Platform

As of August 22, 2011, the Company-owned and operated Ship Shoal 263 platform was processing approximately 6.6 Mmcfed, net to Contango. This platform was designed with a capacity of 40 Mmcfd and 5,000 bopd. This platform services production from our Nautilus well which began producing in June 2010.

Effective October 1, 2010, the Company purchased an additional 7.5% working interest and 6.0% net revenue interest in Ship Shoal 263 for approximately $7.5 million from JEX. The Company now owns a 100% working interest and 80% net revenue interest in this well and platform.

Other Activities

In February 2011, the Company spud its Offshore Gulf of Mexico wildcat exploration well, Vermilion 170 ("Swimmy"), and announced a discovery in March 2011. The Company's independent third party engineer estimates this well to have 8/8ths proved reserves of 48 billion cubic feet of natural gas and 1.2 million barrels of condensate, for a total of approximately 55.2 billion cubic feet equivalent ("Bcfe"), or 37.5 Bcfe net to Contango's 68% net revenue interest, inclusive of its investment in REX. The production platform is currently being installed and we expect to begin production in September 2011 at an estimated rate of 15 Mmcfed, net to Contango. Estimated net costs to Contango, to acquire, drill, complete, and bring this well to full production status are approximately $25.3 million.

Effective February 24, 2011, the Company purchased the deep rights on Ship Shoal 134 from an independent third-party oil and gas company. The exploration plan for our Ship Shoal 121/134 ("Eagle") prospect was approved by the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE") on July 11, 2011. We submitted our application for permit to drill on July 29, 2011 and are hopeful it will be approved in September 2011. Depending on permit approval and rig availability, we expect to spud this well in the September/October 2011 time frame. We will have a 100% working interest in this wildcat exploration prospect and have budgeted approximately $25.0 million to drill this well. We have also invested another $6.0 million in leases associated with Eagle.

In August 2011, we farmed in South Timbalier 75 ("Fang") from an independent third-party oil and gas company. We submitted an exploration plan to the BOEMRE on August 24, 2011 and anticipate it will be approved in early 2012. Under the terms of the farmout agreement, we have until September 2012, subject to rig availability and/or regulatory permit/approval delays, to drill this well. Contango expects to have a 100% working interest and has budgeted to invest approximately $25.0 million to drill this well.

In July 2011, we recompleted our Eloise South well uphole in the CibOp section as our Dutch #5 well, at a cost of approximately $6.0 million, net to Contango. The Company has a 47.05% working interest (38.1% net revenue interest) in

Dutch #5. In addition to this $6.0 million, the Dutch #5 owners purchased the Eloise South well bore from the Eloise South owners (the "Well Cost Adjustment"). The Company invested a net of approximately $2.3 million related to this Well Cost Adjustment.

In June 2011, we completed a workover of our Eloise North well at a cost of approximately $1.8 million, net to Contango.

In September 2010, we drilled our Galveston Area 277L prospect ("His Dudeness"), a wildcat exploration well in the Gulf of Mexico, and determined it was a dry hole. The Company invested approximately $9.5 million, including leasehold costs, to drill, plug and abandon this well.

During the fiscal year ended June 30, 2010, we drilled two dry holes in the Gulf of Mexico. The first was on a farm-in we obtained on block Vermillion 155 ("Paisano"). This well had a dry hole cost of approximately $5.3 million. The second was our Matagorda Island 617 well ("Dude"), with a dry hole cost of approximately $14.9 million. The Company had a 100% working interest in both of these wells.

During the fiscal year ended June 30, 2009, we successfully worked over our Mary Rose #1 well at a cost of approximately $6.1 million, net to Contango, and our Mary Rose # 2 well at a cost of approximately $3.0 million, net to Contango, to reduce water production. We also installed line heaters at a cost of approximately $0.9 million, net to Contango, at the Eugene Island 11 platform which allowed us to further increase our production rate.

Republic Exploration LLC (REX)

West Delta 36, a REX prospect, is operated by a third party. The Company depends on a third-party operator for the operation and maintenance of this production platform. As of August 18, 2011, the well was producing at an 8/8ths rate of approximately 5.5 Mmcfed. REX has a 25.0% working interest ("WI"), and a 20.0% net revenue interest ("NRI"), in this well.

During the fiscal year ended June 30, 2009, COI drilled Eugene Island 56 #1 ("High Country West") and West Delta 77 ("Devil's Elbow"), both REX prospects, which were both determined to be dry holes. COI had a 100% WI and paid 100% of the drilling costs for both wells, which together with leasehold costs and prospect fees totaled approximately $19.6 million.

Contango Offshore Exploration LLC (COE)

Contango Offshore Exploration ("COE") was dissolved on June 1, 2010. Prior to its dissolution, COE was 65.6% owned by Contango, and JEX would generate natural gas and oil prospects through COE. Immediately prior to its dissolution, COE owed the Company $5.9 million in principal and interest under a promissory note (the "COE Note") payable on demand. In connection with the dissolution, the Company assumed its 65.6% share of the obligation under the COE Note, while the other member of COE assumed the remaining 34.4%, or approximately $2 million. This $2 million was paid back to the Company during the fiscal year ended June 30, 2011.

Exploration Alliance with JEX

JEX is a private company formed for the purpose of assembling domestic natural gas and oil prospects, either individually, or through our 32.3% owned affiliated company, REX. We do not have a written agreement with JEX which contractually obligates them to provide us with their services. Once we have purchased a prospect, however, from either JEX or REX, we have historically entered into a participation agreement and joint operating agreement specifying each participant's working interest, net revenue interest, and description of when such interests are earned, as well as allocating an overriding royalty interest of up to 3.33% to benefit employees of JEX.

Offshore Gulf of Mexico Exploration Joint Ventures

Contango, through its wholly-owned subsidiary COI and its partially-owned affiliate, REX, conducts exploration activities in the Gulf of Mexico. During the fourth quarter of the fiscal year ended June 30, 2011, the Company relinquished 12 lease blocks to the BOEMRE, and allowed two additional lease blocks to expire in accordance with their terms. As of August 24, 2011, Contango, through COI and REX, had an interest in 15 offshore leases.

Offshore Properties

Producing Properties. The following table sets forth the interests owned by Contango through its related entities in the Gulf of Mexico which were producing natural gas or oil as of August 24, 2011:

Area/Block	WI	NRI	Status
Eugene Island 10 #D-1 (Dutch #1)	47.05%	38.1%	Producing
Eugene Island 10 #E-1 (Dutch #2)	47.05%	38.1%	Producing
Eugene Island 10 #F-1 (Dutch #3)	47.05%	38.1%	Producing
Eugene Island 10 #G-1 (Dutch #4)	47.05%	38.1%	Producing
Eugene Island 10 #I-1 (Dutch #5)	47.05%	38.1%	Producing
S-L 18640 #1 (Mary Rose #1)	53.21%	40.5%	Producing
S-L 19266 #1 (Mary Rose #2)	53.21%	38.7%	Producing
S-L 19266 #2 (Mary Rose #3)	53.21%	38.7%	Producing
S-L 18860 #1 (Mary Rose #4)	34.58%	25.5%	Producing
S-L 19266 #3 (Eloise North)	36.90%	27.0%	Producing
Ship Shoal 263 (Nautilus)	100.00%	80.0%	Producing
West Delta 36 (via REX)	8.1%	6.5%	Producing

Leases. The following table sets forth the interests owned by Contango through its related entities in leases in the Gulf of Mexico as of August 24, 2011:

Area/Block	WI	Lease Date	Expiration Date
S-L 19261	53.21%	Feb 07	Feb 12
S-L 19396	53.21%	Jun 07	Jun 12
Eugene Island 11	53.21%	Dec 07	Dec-12
East Breaks 369 (1)	(2)	Dec-03	Dec-13
South Timbalier 97 (via REX).	32.30%	Jun-09	Jun-14
Ship Shoal 121	100.00%	Jul-10	Jul-15
Ship Shoal 122	100.00%	Jul-10	Jul-15
Vermilion 170	92.3%	Jul-10	Jul-15
Ship Shoal 134	100.00%	(3)	(3)

(1) Dry Hole
(2) Farm-out. COI retains a 2.41% ORRI
(3) Purchased deep rights. Lease is held by production from shallow wells owned by a third-party

Onshore Exploration and Properties

South Texas.

In May 2011, the Company spud its on-shore wildcat exploration well (Rexer-Tusa #2) in south Texas. On May 13, 2011, the Company sold 75% of its working interest in Rexer-Tusa #2 and the purchaser became the operator. As a result of this sale, the Company now has a 25% working interest (18.4% net revenue interest) before payout, and an 18.8% working interest (13.8% net revenue interest) after payout. The estimated costs to drill, complete and bring this well to production are approximately $1.1 million, net to Contango. See "Property Sales and Discontinued Operations" below for additional information.

Alta Energy Partners LLC

On April 12, 2011, the Company announced a commitment to invest up to $20 million over the next two years in Alta Energy Partners LLC ("Alta Energy"), a venture that will acquire, explore, develop and operate onshore unconventional shale operated and non-operated oil and natural gas assets. Other participants include Alta Resources, LLC and Blackstone Capital Partners. As of August 24, 2011, we had invested approximately $0.4 million in Alta Energy.

Property Sales and Discontinued Operations

On May 13, 2011 the Company sold substantially all of its onshore Texas assets to Patara Oil & Gas LLC ("Patara") for an aggregate purchase price of $40 million ($38.7 million after adjustments). The properties were sold effective April 1, 2011 and consist of the Joint Venture and South Texas assets.

Joint Venture Assets

The Company entered into a joint venture with Patara in October 2009 to develop proved undeveloped Cotton Valley gas reserves in Panola County, Texas. B.A. Berilgen, a member of the Company's board of directors, is the Chief Executive Officer of Patara. The Company sold its 90% interest and 5% overriding royalty interest in the 21 wells drilled under this joint venture. The Company sold the assets for approximately $36.2 million and recognized a pre-tax loss of approximately $0.7 million. These 21 wells had proved reserves of approximately 16.7 Bcfe, net to Contango. The Company has accounted for this sale as discontinued operations as of June 30, 2011 and has included the results of the joint venture operations in discontinued operations for all periods presented.

South Texas

The Company sold 100% of its interest in Rexer #1 and 75% of its interest in Rexer-Tusa #2 for approximately $2.5 million and recognized a pre-tax loss of approximately $0.3 million. Rexer #1 is a wildcat exploration well that was spud in June 2010 and began producing in October 2010. This well had proved reserves of approximately 0.5 Bcfe, net to Contango. Rexer-Tusa #2 is another wildcat exploration well that was spud in May 2011. This well had no proved reserves at the time of sale.

Contango Mining Company

Contango Mining Company ("Contango Mining"), a wholly-owned subsidiary of the Company and the predecessor to Contango ORE, Inc. ("CORE"), was initially formed on October 15, 2009 as a Delaware corporation registered to do business in Alaska for the purpose of engaging in exploration in the State of Alaska for (i) gold and associated minerals and (ii) rare earth elements. Contango Mining held leasehold interests in approximately 647,000 acres from the Tetlin Village Council, the council formed by the governing body for the Native Village of Tetlin, an Alaska Native Tribe ("Tetlin Lease") and held 12,000 acres in unpatented mining claims from the State of Alaska for the exploration of gold deposits and associated minerals (together with the Tetlin Lease, the "Gold Properties"). Contango Mining also held interests in 3,520 acres of unpatented Federal mining claims and 97,280 acres of unpatented mining claims from the State of Alaska for the exploration of rare earth elements (the "REE Properties", and together with the Gold Properties, the "Properties").

On November 29, 2010, CORE, then another wholly-owned subsidiary of the Company, acquired the assets and assumed the obligations of Contango Mining, including the Properties, in exchange for its common stock which was subsequently distributed to the Company's stockholders of record as of October 15, 2010 on the basis of one share of common stock for each ten shares of the Company's common stock then outstanding. No fractional shares were issued, but a cash payment was made to shareholders with less than ten shares based upon the value established for CORE. The Company also contributed $3.5 million in cash to CORE immediately prior to the distribution.

The Company has obtained a valuation report from Avalon Development Corporation, a Fairbanks, Alaska-based mineral exploration consulting firm, of the value of the assets constituting the Properties acquired by CORE. Based on that valuation report and the $3.5 million cash contributed to CORE, the aggregate value of the assets contributed to CORE and distributed to Company shareholders was estimated to be approximately $0.46 per share of Contango Oil & Gas Company. The shares of CORE trade on the OTCBB under the symbol CTGO. The Company no longer has an ownership in CORE and has included its results of operations and gain on disposition in discontinued operations for all periods presented.

Marketing and Pricing

The Company currently derives its revenue principally from the sale of natural gas and oil. As a result, the Company's revenues are determined, to a large degree, by prevailing natural gas and oil prices. The Company currently sells its natural gas and oil on the open market at prevailing market prices. Major purchasers of our natural gas, oil and natural gas liquids for the fiscal year ended June 30, 2011 were Shell Trading US Company (26%), NJR Energy Services (25%), ConocoPhillips Company (23%), Enterprise Products Operating LLC (9%), and TransLouisiana Gas Pipeline Inc. (7%). Market prices are dictated by supply and demand, and the Company cannot predict or control the price it receives for its natural gas and oil. The Company has outsourced the marketing of its offshore natural gas and oil production volume to a privately-held third party marketing firm. The Company has a policy not to hedge its natural gas and oil production.

Price decreases would adversely affect our revenues, profits and the value of our proved reserves. Historically, the prices received for natural gas and oil have fluctuated widely. Among the factors that can cause these fluctuations are:

- The domestic and foreign supply of natural gas and oil
- Overall economic conditions
- The level of consumer product demand

- Adverse weather conditions and natural disasters
- The price and availability of competitive fuels such as heating oil and coal
- Political conditions in the Middle East and other natural gas and oil producing regions
- The level of LNG imports
- Domestic and foreign governmental regulations
- Special taxes on production
- The loss of tax credits and deductions

Competition

The Company competes with numerous other companies in all facets of its business. Our competitors in the exploration, development, acquisition and production business include major integrated oil and gas companies as well as numerous independents, including many that have significantly greater financial resources and in-house technical expertise.

Governmental Regulations

Federal Income Tax. Federal income tax laws significantly affect the Company's operations. The principal provisions affecting the Company are those that permit the Company, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, its domestic "intangible drilling and development costs" and to claim depletion on a portion of its domestic natural gas and oil properties and to claim a manufacturing deduction based on qualified production activities.

Environmental Matters. Domestic natural gas and oil operations are subject to extensive federal regulation and, with respect to federal leases, to interruption or termination by governmental authorities on account of environmental and other considerations such as the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") also known as the "Super Fund Law". The trend towards stricter standards in environmental legislation and regulation could increase costs to the Company and others in the industry. Natural gas and oil lessees are subject to liability for the costs of clean-up of pollution resulting from a lessee's operations, and may also be subject to liability for pollution damages. The Company maintains insurance against costs of clean-up operations, but is not fully insured against all such risks. A serious incident of pollution may also result in the Department of the Interior requiring lessees under federal leases to suspend or cease operation in the affected area.

The Oil Pollution Act of 1990 (the "OPA") and regulations thereunder impose a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by the OPA. In addition, to the extent the Company's offshore lease operations affect state waters, the Company may be subject to additional state and local clean-up requirements or incur liability under state and local laws. The OPA also imposes ongoing requirements on responsible parties, including proof of financial responsibility to cover at least some costs in a potential spill. The Company believes that it currently has established adequate proof of financial responsibility for its offshore facilities. However, the Company cannot predict whether financial responsibility requirements under any OPA amendments will result in the imposition of substantial additional annual costs to the Company in the future or otherwise materially adversely affect the Company. The impact, however, should not be any more adverse to the Company than it will be to other similarly situated or less capitalized owners or operators in the Gulf of Mexico.

The Company's operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Such laws and regulations, among other things, impose absolute liability on the lessee for the cost of clean-up of pollution resulting from a lessee's operations, subject the lessee to liability for pollution damages, may require suspension or cessation of operations in affected areas, and impose restrictions on the injection of liquids into subsurface aquifers that may contaminate groundwater. Such laws could have a significant impact on the operating costs of the Company, as well as the natural gas and oil industry in general. Federal, state and local initiatives to further regulate the disposal of natural gas and oil wastes are also pending in certain jurisdictions, and these initiatives could have a similar impact on the Company. The Company's operations are also subject to additional federal, state and local laws and regulations relating to protection of human health, natural resources, and the environment pursuant to which the Company may incur compliance costs or other liabilities.

Impact of Deepwater Horizon Incident. In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon, engaged in drilling operations for another operator, sank after an apparent blowout and fire. The accident resulted in the loss of life and a significant oil spill. In response to the incident, the Outer Continental Shelf Safety Oversight Board, established by the Secretary of the Interior, issued its recommendations for the strengthening of permitting, inspections, enforcement and environmental stewardship. In addition, the BOEMRE developed an implementation plan for the recommendations, many of which are already underway or planned.

On September 30, 2010, the Department of the Interior announced two new rules (The Drilling Safety Rule and the Workplace Safety Rule) that are intended to improve drilling safety by strengthening requirements for safety equipment, well control systems, and blowout prevention practices on offshore oil and gas operations, and improve workplace safety.

The Deepwater Horizon incident is likely to have a significant and lasting effect on the US offshore energy industry, and will likely result in a number of fundamental changes, including heightened regulatory scrutiny, more stringent operating and safety standards, changes in equipment requirements and the availability and cost of insurance, as well as increased politicization of the industry. These changes may result in increases in our operating and development costs and extend project development timelines because of new regulatory requirements. There may be other impacts of which we are not aware at this time.

Other Laws and Regulations. Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of natural gas and oil including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions in which the Company has production, could be to limit the number of wells that could be drilled on the Company's properties and to limit the allowable production from the successful wells completed on the Company's properties, thereby limiting the Company's revenues.

The BOEMRE administers the natural gas and oil leases held by the Company on federal onshore lands and offshore tracts in the Outer Continental Shelf. The BOEMRE holds a royalty interest in these federal leases on behalf of the federal government. While the royalty interest percentage is fixed at the time that the lease is entered into, from time to time the BOEMRE changes or reinterprets the applicable regulations governing its royalty interests, and such action can indirectly affect the actual royalty obligation that the Company is required to pay. However, the Company believes that the regulations generally do not impact the Company to any greater extent than other similarly situated producers. At the end of lease operations, oil and gas lessees must plug and abandon wells, remove platforms and other facilities, and clear the lease site sea floor. The BOEMRE requires companies operating on the Outer Continental Shelf to obtain surety bonds to ensure performance of these obligations. As an operator, the Company is required to obtain surety bonds of $200,000 per lease for exploration and $500,000 per lease for developmental activities.

The Federal Energy Regulatory Commission (the "FERC") has embarked on wide-ranging regulatory initiatives relating to natural gas transportation rates and services, including the availability of market-based and other alternative rate mechanisms to pipelines for transmission and storage services. In addition, the FERC has announced and implemented a policy allowing pipelines and transportation customers to negotiate rates above the otherwise applicable maximum lawful cost-based rates on the condition that the pipelines alternatively offer so-called recourse rates equal to the maximum lawful cost-based rates. With respect to gathering services, the FERC has issued orders declaring that certain facilities owned by interstate pipelines primarily perform a gathering function, and may be transferred to affiliated and non-affiliated entities that are not subject to the FERC's rate jurisdiction. The Company cannot predict the ultimate outcome of these developments, or the effect of these developments on transportation rates. Inasmuch as the rates for these pipeline services can affect the natural gas prices received by the Company for the sale of its production, the FERC's actions may have an impact on the Company. However, the impact should not be substantially different for the Company than it would be for other similarly situated natural gas producers and sellers.

Risk and Insurance Program

In accordance with industry practice, we maintain insurance against many, but not all, potential perils confronting our operations and in coverage amounts and deductible levels that we believe to be economic. Consistent with that profile, our insurance program is structured to provide us financial protection from significant losses resulting from damages to, or the loss of, physical assets or loss of human life, and liability claims of third parties, including such occurrences as well blowouts and weather events that result in oil spills and damage to our wells and/or platforms. Our goal is to balance the cost of insurance with our assessment of the potential risk of an adverse event. We maintain insurance at levels that we believe are appropriate and consistent with industry practice and we regularly review our risks of loss and the cost and availability of insurance and revise our insurance program accordingly.

While the Company renewed its energy package and insurance policies in January 2011 at rates similar to the prior year, we expect the future availability and cost of insurance to be impacted by the Deepwater Horizon Incident. Impacts could include: tighter underwriting standards, limitations on scope and amount of coverage, and higher premiums, and will depend, in part, on future changes in laws and regulations regarding exploration and production activities in the Gulf of Mexico, including possible increases in liability caps for claims of damages from oil spills. We will continue to monitor the expected regulatory and legislative response and its impact on the insurance market and our overall risk profile, and adjust our risk and insurance program to provide protection at a level that we can afford considering the cost of insurance, against the potential and magnitude of disruption to our operations and cash flows.

We carry insurance protection for our net share of any potential financial losses occurring as a result of events such as the Deepwater Horizon Incident. As a result of the incident, we have increased our well control coverage from $75 million to $100 million on certain wells, which covers control of well, pollution cleanup and consequential damages. We have increased our general liability coverage from $100 million to $150 million, which covers pollution cleanup, consequential damages coverage, and third party personal injury and death. And we have increased our Oil Spill Financial Responsibility coverage from $35 million to $150 million, which covers additional pollution cleanup and third party claims coverage.

Health, Safety and Environmental Program. The Company's Health, Safety and Environmental ("HS&E") Program is supervised by an operating committee of senior management to insure compliance with all state and federal regulations. In addition, to support the operating committee, we have contracted with J. Connors Consulting ("JCC") to manage our regulatory process. JCC is a regulatory consulting firm specializing in the offshore Gulf of Mexico regulatory process, preparation of incident response plans, safety and environmental services and facilitation of comprehensive oil spill response training and drills to oil and gas companies and pipeline operators.

For our Gulf of Mexico operations, we have a Regional Oil Spill Plan in place with the BOEMRE. Our response team is trained annually and is tested through annual spill drills given by the BOEMRE. In addition, we have in place a contract with O'Brien's Response Management ("O'Brien's"). O'Brien's maintains a 24/7 manned incident command center located in Slidell, LA. Upon the occurrence of an oil spill, the Company's spill program is initiated by notifying O'Brien's that we have an emergency. While the Company would focus on source control of the spill, O'Brien's would handle all communication with state and federal agencies as well as U.S. Coast Guard notifications.

If a spill were to occur, we have contracted with Clean Gulf Associates ("CGA") to assist with equipment and personnel needs. CGA specializes in onsite control and cleanup and is on 24 hour alert with equipment currently stored at six bases (Ingleside and Galveston, TX and Lake Charles, Houma, Venice and Pascagoula, LA), and is opening new sites in Leeville, Morgan City and Harvey, LA. The CGA equipment stockpile is available to serve member oil spill response needs including blowouts; open seas, near shore and shallow water skimming; open seas and shoreline booming; communications; dispersants; boat spray systems to apply dispersants; wildlife rehabilitation; and a forward command center. CGA has retainers with an aerial dispersant company and a company that provides mechanical recovery equipment for spill responses. CGA equipment includes:

- HOSS Barge: the largest purpose-built skimming barge in the United States with 4,000 barrels of storage capacity.

- Fast Response System (FRU): a self-contained skimming system for use on vessels of opportunity. CGA has nine of these units.

- Fast Response Vessels (FRV): four 46 foot FRVs with cruise speeds of 20-25 knots that have built-in skimming troughs and cargo tanks, outrigger skimming arms, navigation and communication equipment.

In addition to being a member of CGA, the Company has contracted with Wild Well Control for source control at the wellhead, if required. Wild Well Control is one of the world's leading providers of firefighting, well control, engineering, and training services.

Safety and Environmental Management System. On September 30, 2010, the BOEMRE issued a final rule that requires operators to develop and implement a Safety and Environmental Management System ("SEMS") to address oil and gas operations in the Outer Continental Shelf ("OCS"). The final rule became effective on November 15, 2010 and requires full implementation of the following thirteen mandatory elements of the American Petroleum Institute's Recommended Practice 75 (API RP 75) on or before November 15, 2011:

- General Provisions
- Safety and Environmental Information
- Hazards Analyses
- Management of Change
- Operating Procedures
- Safe Work Practices
- Training
- Mechanical Integrity

- Pre-Startup Review
- Emergency Response and Control
- Investigation of Accidents
- Audits
- Records and Documentation

Our SEMS program must identify, address, and manage safety, environmental hazards, and its impacts during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. The Company is responsible for establishing goals, performance measures, training, accountability for its implementation, and providing necessary resources for an effective SEMS, as well as reviewing the adequacy and effectiveness of the SEMS program. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. We have contracted with Island Technologies Inc. to manage our SEMS program for production operations.

The BOEMRE will enforce the SEMS requirements through audits. We must have our SEMS program audited by either an independent third-party or our designated and qualified personnel within 2 years of the initial implementation and at least once every 3 years thereafter. Failure to implement an effective SEMS program by November 15, 2011 or failure of an audit may force us to shut-in our Gulf of Mexico operations.

Employees

We have eight employees, all of whom are full time. The Company outsources its human resources function to Insperity, Inc. (formerly Administaff Companies II, LP) and all of the Company's employees are co-employees of Insperity, Inc. In addition to our employees, we use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, environmental and tax services. We are dependent on JEX for prospect generation, evaluation and prospect leasing. As a working interest owner, we rely on outside operators to drill, produce and market our natural gas and oil for our onshore prospects and certain offshore prospects where we are a non-operator. In the offshore prospects where we are the operator, we rely on a turn-key contractor to drill and rely on independent contractors to produce and market our natural gas and oil. In addition, we utilize the services of independent contractors to perform field and on-site drilling and production operation services and independent third party engineering firms to calculate our reserves.

Directors and Executive Officers

The following table sets forth the names, ages and positions of our directors and executive officers:

Name	Age	Position
Kenneth R. Peak	66	Chairman, Chief Executive Officer and Director
Sergio Castro	42	Vice President, Chief Financial Officer, Treasurer and Secretary
Yaroslava Makalskaya.......	42	Vice President, Controller and Chief Accounting Officer
Charles A. Cambron	44	Vice President of Operations
Marc Duncan	58	Safety, Environmental and Regulatory Compliance Officer (SEARCO)
B.A. Berilgen.....................	63	Director
Jay D. Brehmer..................	46	Director
Charles M. Reimer.............	66	Director
Steven L. Schoonover........	66	Director

Kenneth R. Peak. Mr. Peak is the founder of the Company and has been Chairman and Chief Executive Officer since its formation in September 1999. Mr. Peak entered the energy industry in 1973 as a commercial banker and held a variety of financial and executive positions in the oil and gas industry prior to starting Contango in 1999. Mr. Peak served as an officer in the U.S. Navy from 1968 to 1971. Mr. Peak received a BS in physics from Ohio University in 1967, and an MBA from Columbia University in 1972. He currently serves as a director of Patterson-UTI Energy, Inc., a provider of onshore contract drilling services to exploration and production companies in North America.

Sergio Castro. Mr. Castro joined Contango in March 2006 as Treasurer and was appointed Vice President, Treasurer and Secretary in April 2006 and Chief Financial Officer in June 2010. Prior to joining Contango, Mr. Castro spent two years (April 2004 to March 2006) as a consultant for UHY Advisors TX, LP. From January 2001 to April 2004, Mr. Castro was a lead credit analyst for Dynegy Inc. From August 1997 to January 2001, Mr. Castro worked as an auditor for Arthur Andersen LLP, where he specialized in energy companies. Mr. Castro was honorably discharged from the U.S. Navy in 1993 as an E-6, where he served onboard a nuclear powered submarine. Mr. Castro received a BBA in Accounting in 1997 from the University of Houston, graduating summa cum laude. Mr. Castro is a CPA and a Certified Fraud Examiner.

Yaroslava Makalskaya. Ms. Makalskaya joined Contango in March 2010 and was appointed Vice President, Controller and Chief Accounting Officer in June 2010. Prior to joining Contango, Ms. Makalskaya was a director of the Transaction Services practice at PricewaterhouseCoopers, where she assisted clients with M&A transactions as well as advised clients with complex accounting and financial reporting issues. Prior to July 2008 Ms. Makalskaya was a Senior Manager in the audit practice of PricewaterhouseCoopers and Arthur Andersen, where her clients included many US and international companies in energy, utilities, mining and other sectors. Ms. Makalskaya holds a MS degree in Economics from Novosibirsk State University in Russia. Ms. Makalskaya is a CPA and has approximately 19 years of experience in accounting and finance, including 13 years in public accounting.

Charles A. Cambron. Mr. Cambron joined Contango in August 2010 as Vice President of Operations. Mr. Cambron has over 20 years of experience in the Gulf of Mexico oil and gas industry. Most recently he was employed by Applied Drilling Technology, Inc. (ADTI) as an Operations Manager from August 1995 until August 2010. He also held various positions in engineering and offshore supervision over a 15 year period. Prior to ADTI, Mr. Cambron began his career with Rowan Petroleum, Inc. as a Drilling Engineer working in both the Gulf of Mexico and North Sea. Mr. Cambron received a BS degree in Petroleum Engineering from the University of Oklahoma in 1991.

Marc Duncan. Mr. Duncan joined Contango in June 2005 as President and Chief Operating Officer of Contango Operators, Inc. and was appointed President and Chief Operating Officer of Contango Oil & Gas Company in October 2006 until December 2010. In December 2010 Mr. Duncan was appointed as the Company’s Safety, Environmental and Regulatory Compliance Officer (“SEARCO”). Mr. Duncan has over 37 years of experience in the energy industry and has held a variety of domestic and international engineering and senior-level operations management positions relating to natural gas and oil exploration, project development, and drilling and production operations. Prior to joining Contango, Mr. Duncan served as Chief Operating Officer of USENCO International, Inc. and its subsidiaries and affiliates in China and Ukraine from February 2000 to July 2004 and as a senior project and drilling engineer for Hunt Oil Company from July 2004 to June 2005. He holds an MBA in Engineering Management from the University of Dallas, an MEd from the University of North Texas and a BS in Science and Education from Stephen F. Austin University.

B.A. Berilgen. Mr. Berilgen was appointed a director of Contango in July 2007. Mr. Berilgen has served in a variety of senior positions during his 40 year career. Most recently, he became Chief Executive Officer of Patara Oil & Gas LLC in April 2008. Prior to that he was Chairman, Chief Executive Officer and President of Rosetta Resources Inc., a company he founded in June 2005, until his resignation in July 2007, and then he was an independent consultant from July 2007 through April 2008. Mr. Berilgen was also previously the Executive Vice President of Calpine Corp. and President of Calpine Natural Gas L.P. from October 1999 through June 2005. In June 1997, Mr. Berilgen joined Sheridan Energy, a public oil and gas company, as its President and Chief Executive Officer. Mr. Berilgen attended the University of Oklahoma, receiving a B.S. in Petroleum Engineering in 1970 and a M.S. in Industrial Engineering / Management Science.

Jay D. Brehmer. Mr. Brehmer has been a director of Contango since October 2000. Mr. Brehmer is a co-founding partner of Southplace, LLC, a provider of private-company middle-market corporate finance advisory services. Mr. Brehmer founded Southplace, LLC in November 2002. In August 2004, Mr. Brehmer became Managing Director of Houston Capital Advisors LP, a boutique financial advisory, merger and acquisition investment bank, while still retaining his membership in Southplace, LLC. Mr. Brehmer resigned from Houston Capital Advisors LP in January 2008 and is currently associated with Southplace, LLC in a full-time capacity. From May 1998 until November 2002, Mr. Brehmer was responsible for structured-finance energy related transactions at Aquila Energy Capital Corporation. Prior to joining Aquila, Mr. Brehmer founded Capital Financial Services, which provided mid-cap companies with strategic merger and acquisition advice coupled with prudent financial capitalization structures. Mr. Brehmer holds a BBA from Drake University in Des Moines, Iowa.

Charles M. Reimer. Mr. Reimer was elected a director of Contango in November 2005. Mr. Reimer is President of Freeport LNG Development, L.P., and has experience in exploration, production, liquefied natural gas (“LNG”) and business development ventures, both domestically and abroad. From 1986 until 1998, Mr. Reimer served as the senior executive responsible for the VICO joint venture that operated in Indonesia, and provided LNG technical support to P. T. Badak. Additionally, during these years he served, along with Pertamina executives, on the board of directors of the P.T. Badak LNG plant in Bontang, Indonesia. Mr. Reimer began his career with Exxon Company USA in 1967 and held various professional and management positions in Texas and Louisiana. Mr. Reimer was named President of Phoenix Resources Company in 1985 and relocated to Cairo, Egypt, to begin eight years of international assignments in both Egypt and Indonesia. Prior to joining Freeport LNG Development, L.P. in December 2002, Mr. Reimer was President and Chief Executive Officer of Cheniere Energy, Inc.

Steven L. Schoonover. Mr. Schoonover was elected a director of Contango in November 2005. Mr. Schoonover was most recently Chief Executive Officer of Cellxion, L.L.C., a company he founded in September 1996 and sold in September 2007, which specialized in construction and installation of telecommunication buildings and towers, as well as the installation of high-tech telecommunication equipment. Since the sale in September 2007, Mr. Schoonover continues to serve as a consultant to the current management team of Cellxion, L.L.C. From 1990 until its sale in November 1997 to Telephone Data Systems, Inc., Mr. Schoonover served as President of Blue Ridge Cellular, Inc., a full-service cellular telephone company he co-founded. From 1983 to 1996, he served in various positions, including President and Chief Executive Officer, with Fibrebond Corporation, a construction firm involved in cellular telecommunications buildings, site development and tower construction. Mr. Schoonover has been awarded, on two occasions with two different companies, Entrepreneur of the Year, sponsored by Ernst & Young, Inc Magazine and USA Today.

Directors of Contango serve as members of the board of directors until the next annual stockholders meeting, until successors are elected and qualified or until their earlier resignation or removal. Officers of Contango are elected by the board of directors and hold office until their successors are chosen and qualified, until their death or until they resign or have been removed from office. All corporate officers serve at the discretion of the board of directors. During fiscal year 2011 and 2010, each outside director of the Company received a quarterly retainer of $20,000 payable in cash, with no stock option or common stock grants. There were no additional payments for meetings attended or being chairman of a committee. There are no family relationships between any of our directors or executive officers.

During fiscal year 2009, each outside director of the Company received a quarterly retainer of $8,000 payable in cash and $36,000 payable annually in Company common stock. Each outside director also received a $1,000 cash payment for each board meeting and separately scheduled Audit Committee meeting attended. The Chairman of the Audit Committee received an additional quarterly cash payment of $3,000.

Corporate Offices

We lease our corporate offices at 3700 Buffalo Speedway, Suite 960, Houston, Texas 77098. In November 2010, the Company expanded its office space and extended its office lease agreement through December 31, 2015.

Code of Ethics

We adopted a Code of Ethics for senior management in December 2002. A copy of our Code of Ethics is filed as an exhibit to this Form 10-K and is also available on our Website at www.contango.com.

Available Information

General information about us can be found on our website at www.contango.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website as soon as reasonably practicable after we file or furnish them to the Securities and Exchange Commission (“SEC”).

Item 1A. *Risk Factors*

In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the following factors when evaluating the Company. An investment in the Company is subject to risks inherent in our business. The trading price of the shares of the Company is affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in the Company may decrease, resulting in a loss.

We have no ability to control the market price for natural gas and oil. Natural gas and oil prices fluctuate widely, and a substantial or extended decline in natural gas and oil prices would adversely affect our revenues, profitability and growth and could have a material adverse effect on the business, the results of operations and financial condition of the Company.

Our revenues, profitability and future growth depend significantly on natural gas and crude oil prices. Prices received affect the amount of future cash flow available for capital expenditures and repayment of indebtedness and our ability to raise additional capital. We do not expect to hedge our production to protect against price decreases. Lower prices may also affect the amount of natural gas and oil that we can economically produce. Factors that can cause price fluctuations include:

- Overall economic conditions.
- The domestic and foreign supply of natural gas and oil.

- The level of consumer product demand.
- Adverse weather conditions and natural disasters.
- The price and availability of competitive fuels such as LNG, heating oil and coal.
- Political conditions in the Middle East and other natural gas and oil producing regions.
- The level of LNG imports.
- Domestic and foreign governmental regulations.
- Special taxes on production.
- Access to pipelines and gas processing plants.
- The loss of tax credits and deductions.

A substantial or extended decline in natural gas and oil prices could have a material adverse effect on our access to capital and the quantities of natural gas and oil that may be economically produced by us. A significant decrease in price levels for an extended period would negatively affect us.

We depend on the services of our Chairman and Chief Executive Officer, and implementation of our business plan could be seriously harmed if we lost his services.

We depend heavily on the services of Kenneth R. Peak, our Chairman and Chief Executive Officer. We do not have an employment agreement with Mr. Peak, and the proceeds from a $10.0 million “key person” life insurance policy on Mr. Peak may not be adequate to cover our losses in the event of Mr. Peak’s death.

We are highly dependent on the technical services provided by JEX and could be seriously harmed if JEX terminated its services with us or became otherwise unavailable.

Because we employ no geoscientists or petroleum engineers, we are dependent upon JEX for the success of our natural gas and oil exploration projects and expect to remain so for the foreseeable future. We do not have a written agreement with JEX which contractually obligates JEX to provide us with its services in the future. Highly qualified explorationists and engineers are difficult to attract and retain. As a result, the loss of the services of JEX could have a material adverse effect on us and could prevent us from pursuing our business plan. Additionally, the loss by JEX of certain explorationists could have a material adverse effect on our operations as well. We have historically entered into agreements with JEX and its affiliates when we purchase prospects from JEX and its affiliates that specify the terms and conditions of purchase.

Our ability to successfully execute our business plan is dependent on our ability to obtain adequate financing.

Our business plan, which includes participation in 3-D seismic shoots, lease acquisitions, the drilling of exploration prospects and producing property acquisitions, has required and is expected to continue to require substantial capital expenditures. We may require additional financing to fund our planned growth. Our ability to raise additional capital will depend on the results of our operations and the status of various capital and industry markets at the time we seek such capital. Accordingly, additional financing may not be available to us on acceptable terms, if at all. In the event additional capital resources are unavailable, we may be required to curtail our exploration and development activities or be forced to sell some of our assets in an untimely fashion or on less than favorable terms.

It is difficult to quantify the amount of financing we may need to fund our planned growth. The amount of funding we may need in the future depends on various factors such as:

- Our financial condition.
- The prevailing market price of natural gas and oil.
- The type of projects in which we are engaging.
- The lead time required to bring any discoveries to production.

We frequently obtain capital through the sale of our producing properties.

The Company, since its inception in September 1999, has raised approximately $524 million from various property sales. These sales bring forward future revenues and cash flows, but our longer term liquidity could be impaired to the extent our exploration efforts are not successful in generating new discoveries, production, revenues and cash flows. Additionally, our longer term liquidity could be impaired due to the decrease in our inventory of producing properties that could be sold in future periods. Further, as a result of these property sales the Company’s ability to collateralize bank borrowings is reduced which increases our dependence on more expensive mezzanine debt and potential equity sales. The availability of such funds will depend upon prevailing market conditions and other factors over which we have no control, as well as our financial condition and results of operations.

We assume additional risk as Operator in drilling high pressure and high temperature wells in the Gulf of Mexico.

COI, a wholly-owned subsidiary of the Company, was formed for the purpose of drilling and operating exploration wells in the Gulf of Mexico. Drilling activities are subject to numerous risks, including the significant risk that no commercially productive hydrocarbon reserves will be encountered. The cost of drilling, completing and operating wells and of installing production facilities and pipelines is often uncertain. Drilling costs could be significantly higher if we encounter difficulty in drilling offshore exploration wells. The Company's drilling operations may be curtailed, delayed, canceled or negatively impacted as a result of numerous factors, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery or availability of material, equipment and fabrication yards. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs, drilling vessels, supply boats and personnel experienced in the oil and gas industry in general, and the offshore oil and gas industry in particular. This may lead to difficulty and delays in consistently obtaining certain services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates and scheduling equipment fabrication at factories and fabrication yards. This, in turn, may lead to projects being delayed or experiencing increased costs. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or we may not recover all or any of our investment. The risk of significant cost overruns, curtailments, delays, inability to reach our target reservoir and other factors detrimental to drilling and completion operations may be higher due to our inexperience as an operator.

Additionally, we use turnkey contracts that may cost more than drilling contracts at daily rates. Should our contracts come off turnkey due to events such as adverse weather conditions, difficulties encountered while drilling, or the termination of such turnkey contract by the turnkey drilling contractor (under certain conditions), our drilling costs could be significantly higher.

We rely on third-party operators to operate and maintain some of our production pipelines and processing facilities and, as a result, we have limited control over the operations of such facilities. The interests of an operator may differ from our interests.

We depend upon the services of third-party operators to operate production platforms, pipelines, gas processing facilities and the infrastructure required to produce and market our natural gas, condensate and oil. We have limited influence over the conduct of operations by third-party operators. As a result, we have little control over how frequently and how long our production is shut-in when production problems, weather and other production shut-ins occur. Poor performance on the part of, or errors or accidents attributable to, the operator of a project in which we participate may have an adverse effect on our results of operations and financial condition. Also, the interest of an operator may differ from our interests.

Repeated production shut-ins can possibly damage our well bores.

Our well bores are required to be shut-in from time to time due to a variety of issues, including a combination of weather, mechanical problems, sand production, bottom sediment, water and paraffin associated with our condensate production at our Eugene Island 11 platform, as well as downstream third-party facility and pipeline shut-ins. In addition, shut-ins are necessary from time to time to upgrade and improve the production handling capacity at related downstream platform, gas processing and pipeline infrastructure. In addition to negatively impacting our near term revenues and cash flow, repeated production shut-ins may damage our well bores if repeated excessively or not executed properly. The loss of a well bore due to damage could require us to drill additional wells.

Concentrating our capital investment in the Gulf of Mexico increases our exposure to risk.

Our capital investments are focused in offshore Gulf of Mexico exploration prospects, which may result in a total loss of our investment. Furthermore, even our productive wells may not result in profitable operations.

Gulf of Mexico exploration efforts have been on-going for over 60 years and remaining prospects are at deeper, more expensive horizons and often in much deeper water depths. As a result, a number of companies have decided to shift their focus to onshore "shale plays." The Company's continuing focus on the Gulf of Mexico will result in significant dry hole costs, perhaps in excess of $30 million for one well, which significantly concentrates and increases our risk profile.

Natural gas and oil reserves are depleting assets and the failure to replace our reserves would adversely affect our production and cash flows.

Our future natural gas and oil production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows will be adversely impacted. Production from natural gas and oil properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Further, the majority of our reserves are proved developed producing. Accordingly, we do not have significant opportunities to increase our production from our existing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves. If we are not successful, our future production and revenues will be adversely affected.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities of our reserves.

There are numerous uncertainties in estimating crude oil and natural gas reserves and their value, including many factors that are beyond our control. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves shown in this report.

In order to prepare these estimates, our independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves shown in a reserve report. In addition, estimates of our proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control and may prove to be incorrect over time. As a result, our estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in our reserve report have produced for a relatively short period of time. Accordingly, some of our reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect our financial condition, future prospects and market value.

The Company’s reserves and revenues are primarily concentrated in one field.

Approximately 83% of our proved reserves are assigned to our Dutch, Mary Rose and Eloise discoveries which have ten producing well bores concentrated in two reservoirs on one field, and are producing through two production platforms. Reserve assessments based on only ten well bores in two reservoirs are subject to significantly greater risk of being shut-in for a variety of weather, platform and pipeline difficulties. In addition, the risk of a downward revision in our reserve estimates is also greater.

We rely on the accuracy of the estimates in the reservoir engineering reports provided to us by our outside engineers.

We have no in house reservoir engineering capability, and therefore rely on the accuracy of the periodic reservoir reports provided to us by our independent third-party reservoir engineers. If those reports prove to be inaccurate, our financial reports could have material misstatements. Further, we use the reports of our independent reservoir engineers in our financial planning. If the reports of the outside reservoir engineers prove to be inaccurate, we may make misjudgments in our financial planning.

Exploration is a high risk activity, and our participation in drilling activities may not be successful.

Our future success largely depends on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the significant risk that no commercially productive natural gas or oil reservoirs will be discovered. The cost of drilling, completing and operating wells is uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Unexpected drilling conditions.
- Blowouts, fires or explosions with resultant injury, death or environmental damage.
- Pressure, temperature or other irregularities in formations.
- Equipment failures and/or accidents caused by human error.
- Tropical storms, hurricanes and other adverse weather conditions.
- Compliance with governmental requirements and laws, present and future.

- Shortages or delays in the availability of drilling rigs and the delivery of equipment.
- Our turnkey drilling contracts reverting to a day rate contract or our turnkey contractor electing to terminate the turnkey contract would significantly increase the cost and risk to the Company.
- Problems at third-party operated platforms, pipelines and gas processing facilities over which we have no control.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. Poor results from our drilling activities would materially and adversely affect our future cash flows and results of operations.

In addition, as a "successful efforts" company, we choose to account for unsuccessful exploration efforts (the drilling of "dry holes") and seismic costs as a current expense of operations, which immediately impacts our earnings. Significant expensed exploration charges in any period would materially adversely affect our earnings for that period and cause our earnings to be volatile from period to period.

Production activities in the Gulf of Mexico increase our susceptibility to pollution and natural resource damage.

A blowout, rupture or spill of any magnitude would present serious operational and financial challenges. Most of the Company's operations are on the Gulf of Mexico shelf in water depths less than 200 feet and less than 50 miles from the coast. Such proximity to the shore-line increases the probability of a biological impact or damaging the fragile eco-system in the event of released condensate.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions in the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including countries in the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.

The Environmental Protection Agency (the "EPA") has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. EPA has proposed such greenhouse gas regulations and may issue final rules at a subsequent date.

Several decisions have been issued by courts that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the natural gas and condensate that we produce.

The natural gas and oil business involves many operating risks that can cause substantial losses and our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

The natural gas and oil business involves a variety of operating risks, including:

- Blowouts, fires and explosions.
- Surface cratering.

- Uncontrollable flows of underground natural gas, oil or formation water.
- Natural disasters.
- Pipe and cement failures.
- Casing collapses.
- Stuck drilling and service tools.
- Reservoir compaction.
- Abnormal pressure formations.
- Environmental hazards such as natural gas leaks, oil spills, pipeline ruptures or discharges of toxic gases.
- Capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which we have no control.
- Repeated shut-ins of our well bores could significantly damage our well bores.
- Required workovers of existing wells that may not be successful.

If any of the above events occur, we could incur substantial losses as a result of:

- Injury or loss of life.
- Reservoir damage.
- Severe damage to and destruction of property or equipment.
- Pollution and other environmental damage.
- Clean-up responsibilities.
- Regulatory investigations and penalties.
- Suspension of our operations or repairs necessary to resume operations.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances, operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

If we were to experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, any one of which could adversely affect our ability to conduct operations. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. We may not be able to maintain adequate insurance in the future at rates we consider reasonable, and particular types of coverage may not be available. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

Not hedging our production may result in losses.

Due to the significant volatility in natural gas prices and the potential risk of significant hedging losses if our production should be shut-in during a period when NYMEX natural gas prices increase, our policy is to hedge only through the purchase of puts. By not hedging our production, we may be more adversely affected by declines in natural gas and oil prices than our competitors who engage in hedging arrangements.

Our ability to market our natural gas and oil may be impaired by capacity constraints and equipment malfunctions on the platforms, gathering systems, pipelines and gas plants that transport and process our natural gas and oil.

All of our natural gas and oil is transported through gathering systems, pipelines, processing plants, and offshore platforms. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilized by other natural gas or oil shippers that may have priority transportation agreements. If the gathering systems, processing plants, platforms or our transportation capacity is materially restricted or is unavailable in the future, our ability to market our natural gas or oil could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on our financial condition and results of operations. Further, repeated shut-ins of our wells could result in damage to our well bores that would impair our ability to produce from these wells and could result in additional wells being required to produce our reserves.

We may not have title to our leased interests and if any lease is later rendered invalid, we may not be able to proceed with our exploration and development of the lease site.

Our practice in acquiring exploration leases or undivided interests in natural gas and oil leases is to not incur the expense of retaining title lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of JEX and others to perform the field work in examining records in the appropriate governmental, county or parish clerk's office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to the drilling of an exploration well the operator of the well will typically obtain a preliminary title review of the drillsite lease and/or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. However, such deficiencies may not have been cured by the operator of such wells. It does happen, from time to time, that the examination made by title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect. It may also happen, from time to time, that the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion.

Competition in the natural gas and oil industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with a broad range of natural gas and oil companies in our exploration and property acquisition activities. We also compete for the equipment and labor required to operate and to develop these properties. Many of our competitors have substantially greater financial resources than we do. These competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties. Further, they may be able to evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil and to acquire additional properties in the future depends on our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating for a much longer time than we have and have substantially larger staffs. We may not be able to compete effectively with these companies or in such a highly competitive environment.

The proposed United States federal budget for 2011 and other pending legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

In February 2009, the current federal administration released its budget proposals for 2010, which included numerous proposed tax changes. In April 2009, legislation was introduced to further these objectives and in February 2010, the federal administration released similar budget proposals for 2011. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by oil and gas companies in the United States and impose new taxes. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands. Should some or all of these provisions become law, taxes on the E&P industry would increase, which could have a negative impact on our results of operations and cash flows. Although these proposals initially were made in 2009, none have become law. It is still, however, the federal administration's stated intention to enact legislation to repeal tax incentives and deductions and impose new taxes on oil and gas companies.

We are subject to complex laws and regulations, including environmental regulations that can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment. Failure to comply with such rules and regulations could result in substantial penalties and have an adverse effect on us. These laws and regulations:

- Require that we obtain permits before commencing drilling.
- Restrict the substances that can be released into the environment in connection with drilling and production activities.
- Limit or prohibit drilling activities on protected areas, such as wetlands or wilderness areas.
- Require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells.

Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. We maintain only limited insurance coverage for sudden and accidental environmental damages. Accordingly, we may be subject to liability, or we may be required to cease production from properties in the event of environmental damages. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed and any such changes could have an adverse effect on our business and results of operations.

Our operations in the Gulf of Mexico have been adversely affected by changes in laws and regulations which have occurred and are expected to continue to occur as a result of the Deepwater Horizon Incident.

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon was engaged in drilling operations for another operator and sank after an apparent blowout and fire. The accident resulted in the loss of life and a significant oil spill. As a result, the Department of the Interior issued a directive calling for additional safety and performance standards as well as rigorous monitoring and testing requirements. In addition, various Congressional committees began pursuing legislation to regulate drilling activities, establish safety requirements and increase liability for oil spills.

We continue to monitor legislative and regulatory developments, including the Drilling Safety Rule and the Workforce Safety Rule issued by the Department of the Interior. However, the full legislative and regulatory response to the incident is not fully known. An expansion of safety and performance regulations or an increase in liability for drilling activities will have one or more of the following impacts on our business:

- Increase the costs of drilling exploratory and development wells.
- Cause delays in, or preclude, the development of projects in the Gulf of Mexico.
- Result in longer time periods to obtain permits.
- Result in higher operating costs.
- Increase or remove liability caps for claims of damages from oil spills.
- Limit our ability to obtain additional insurance coverage on commercially reasonable terms to protect against any increase in liability.

Any of the above factors may result in a reduction of our cash flows, profitability, and the fair value of our properties.

New regulatory requirements and permitting procedures recently imposed by the BOEMRE have significantly delayed our ability to obtain permits to drill new wells in offshore waters.

Subsequent to the Deepwater Horizon incident in the Gulf of Mexico, the BOEMRE issued a series of Notices to Lessees ("NTLs") imposing new regulatory requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. These new regulatory requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.
- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, and also requires certifications of compliance from senior corporate officers.
- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.
- The Workplace Safety Rule, which requires operators to have a comprehensive SEMS program in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills.

Since the adoption of these new regulatory requirements, BOEMRE has been taking much longer to review and approve permits for new wells. Due to the extremely slow pace of permit review and approval, the BOEMRE may now take four months or longer to approve applications for drilling permits that were previously approved in less than 30 days. The new rules also increase the cost of preparing each permit application and will increase the cost of each new well.

The BOEMRE has implemented much more stringent controls and reporting requirements that if not followed, could result in significant monetary penalties or a shut-in of all or a portion of our Gulf of Mexico operations.

The BOEMRE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. They are responsible for leading the most aggressive and comprehensive reforms to offshore oil and gas regulation and oversight in U.S. history. Their reforms strengthen requirements for everything from well design and workplace safety to corporate accountability.

One of the many reforms includes implementing a SEMS program. This program requires operators to identify, address, and manage safety, environmental hazards, and its impacts during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all applicable governmental regulations. Failure to implement an effective and robust SEMS program by November 15, 2011 or failure to comply with the program may force us to cease operations in the Gulf of Mexico.

Additionally, the OCS Lands Act authorizes and requires the BOEMRE to provide for both an annual scheduled inspection and a periodic unscheduled (unannounced) inspection of all oil and gas operations on the OCS. In addition to examining all safety equipment designed to prevent blowouts, fires, spills, or other major accidents, the inspections focus on pollution, drilling operations, completions, workovers, production, and pipeline safety. Upon detecting a violation, the inspector issues an Incident of Noncompliance ("INC") to the operator and uses one of two main enforcement actions (warning or shut- in), depending on the severity of the violation. If the violation is not severe or threatening, a warning INC is issued. The warning INC must be corrected within a reasonable amount of time specified on the INC. The shut-in INC may be for a single component (a portion of the facility) or the entire facility. The violation must be corrected before the operator is allowed to continue the activity in question.

In addition to the enforcement actions specified above, the BOEMRE can assess a civil penalty of up to $35,000 per violation per day if: 1) the operator fails to correct the violation in the reasonable amount of time specified on the INC; or 2) the violation resulted in a threat of serious harm or damage to human life or the environment. Operators with excessive INCs may be forced to cease operations in the Gulf of Mexico.

We do not control the activities on properties we do not operate.

Other companies may from time to time drill, complete and operate properties in which we have an interest. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including:

- Timing and amount of capital expenditures.
- The operator's expertise and financial resources.
- Approval of other participants in drilling wells.
- Selection of technology.

We are highly dependent on our management team, JEX, our exploration partners and third-party consultants and any failure to retain the services of such parties could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy is highly dependent on our management team, as well as certain key geoscientists, geologists, engineers and other professionals engaged by us. We are highly dependent on the services provided by JEX and we do not have any written agreements contractually obligating them to provide us with their services in the future. The loss of key members of our management team, JEX or other highly qualified technical professionals could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies which may have a material adverse effect on our business, financial condition and operating results.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

We expect to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of natural gas and oil properties requires an assessment of:

- Recoverable reserves.
- Exploration potential.
- Future natural gas and oil prices.
- Operating costs.
- Potential environmental and other liabilities and other factors.
- Permitting and other environmental authorizations required for our operations.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are necessarily inexact and their accuracy inherently uncertain and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every platform or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken.

Future acquisitions could pose additional risks to our operations and financial results, including:

- Problems integrating the purchased operations, personnel or technologies.
- Unanticipated costs.
- Diversion of resources and management attention from our exploration business.
- Entry into regions or markets in which we have limited or no prior experience.
- Potential loss of key employees of the acquired organization.

Anti-takeover provisions of our certificate of incorporation, bylaws and Delaware law could adversely effect a potential acquisition by third-parties that may ultimately be in the financial interests of our stockholders.

Our Certificate of Incorporation, Bylaws and the Delaware General Corporation Law contain provisions that may discourage unsolicited takeover proposals. These provisions could have the effect of inhibiting fluctuations in the market price of our common stock that could result from actual or rumored takeover attempts, preventing changes in our management or limiting the price that investors may be willing to pay for shares of common stock.

The Company adopted a Stockholders Rights Plan in September 2008, which will terminate September 30, 2011, that is designed to ensure that all stockholders of the Company receive fair value for their shares of common stock in a proposed takeover of the Company and to guard against coercive takeover tactics to gain control of the Company. In addition, these provisions, among other things, authorize the board of directors to:

- Designate the terms of and issue new series of preferred stock.
- Limit the personal liability of directors.
- Limit the persons who may call special meetings of stockholders.
- Prohibit stockholder action by written consent.
- Establish advance notice requirements for nominations for election of the board of directors and for proposing matters to be acted on by stockholders at stockholder meetings.
- Require us to indemnify directors and officers to the fullest extent permitted by applicable law.
- Impose restrictions on business combinations with some interested parties.

Item 1B. ***Unresolved Staff Comments***

None

Item 2. ***Properties***

Production, Prices and Operating Expenses

The following table presents information regarding the production volumes, average sales prices received and average production costs associated with our sales of natural gas, oil and natural gas liquids ("NGLs") from continuing operations for the periods indicated. Oil, condensate and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of oil, condensate or NGL is the energy equivalent of six thousand cubic feet ("Mcf") of natural gas. Reported lease operating expenses include property and severance taxes.

	Year Ended June 30,		
	2011	**2010**	**2009**
Production:			
Natural gas (million cubic feet)	24,742	21,081	20,535
Oil and condensate (thousand barrels)	675	504	515
Natural gas liquids (thousand gallons)	26,926	24,690	24,803
Total (million cubic feet equivalent)	32,639	27,632	27,168
Natural gas (million cubic feet per day)	67.8	57.8	56.3
Oil and condensate (thousand barrels per day)	1.8	1.4	1.4
Natural gas liquids (thousand gallons per day)	73.8	67.6	68.0
Total (million cubic feet equivalent per day)	89.1	75.9	74.4

	Year Ended June 30,		
	2011	2010	2009
Average sales price:			
Natural gas (per thousand cubic feet)	$ 4.39	$ 4.48	$ 6.34
Oil and condensate (per barrel)	$ 91.97	$ 77.18	$ 67.72
Natural gas liquids (per gallon)	$ 1.23	$ 1.04	$ 1.03
Total (per thousand cubic feet equivalent)	$ 6.24	$ 5.75	$ 7.02
Selected data per Mcfe:			
Total lease operating expenses	$ 0.80	$ 0.60	$ 0.87
General and administrative expenses	$ 0.38	$ 0.17	$ 0.35
Depreciation, depletion and amortization of natural gas and oil properties	$ 1.68	$ 1.24	$ 1.17

Not included in the table above is production information from our discontinued operations. For the fiscal year ended June 30, 2011, our discontinued operations produced approximately 1,418 Mmcf of natural gas, 10.3 MBbls of condensate, and 2.6 million gallons of natural gas liquids at an average price of $3.31 per Mcf, $86.40 per Bbl and $0.96 per gallon, respectively. For the fiscal year ended June 30, 2010, our discontinued operations produced approximately 305 Mmcf of natural gas, 1.2 MBbls of condensate, and 428 thousand gallons of natural gas liquids at an average price of $3.72 per Mcf, $75.90 per Bbl and $1.04 per gallon, respectively.

Development, Exploration and Acquisition Expenditures

The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated:

	Year Ended June 30,		
(thousands)	2011	2010	2009
Property acquisition costs:			
Unproved	$ 2,802	$ 11,319	$ -
Proved	10,135	2,009	1,131
Exploration costs	14,016	52,805	23,285
Developmental costs	39,211	40,902	22,890
Total costs	$ 66,164	$ 107,035	$ 47,306

Drilling Activity

The following table shows our drilling activity for the periods indicated. In the table, “gross” wells refer to wells in which we have a working interest, and “net” wells refer to gross wells multiplied by our working interest in such wells.

	Year Ended June 30,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	9	7.5	14	14.0	-	-
Productive (offshore)	1	1.0	2	1.3	2	0.8
Non-productive (onshore)	-	-	-	-	-	-
Non-productive (offshore)	1	1.0	2	2.0	2	2.0
Total	11	9.5	18	17.3	4	2.8

For the fiscal year ended June 30, 2011, of the nine productive onshore wells listed above, one relates to the Rexer-Tusa #2 well and eight relate to our Conterra Company wells. For the fiscal year ended June 30, 2010, of the 14 productive onshore wells listed above, one relates to our Rexer #1 well and 13 relate to our Conterra Company wells. The Conterra Company wells were sold on May 13, 2011 and are classified as discontinued operations in our financial statements.

Exploration and Development Acreage

Our principal natural gas and oil properties consist of natural gas and oil leases. The following table indicates our interests in developed and undeveloped acreage as of June 30, 2011:

	Developed Acreage (1)(2)		Undeveloped Acreage (1)(3)	
	Gross (4)	Net (5)	Gross (4)	Net (5)
Onshore Texas	834	209	-	-
Offshore Gulf of Mexico...	21,897	13,541	21,035	17,165
Total	22,731	13,750	21,035	17,165

(1) Excludes any interest in acreage in which we have no working interest before payout or before initial production.
(2) Developed acreage consists of acres spaced or assignable to productive wells.
(3) Undeveloped acreage is considered to be those 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.
(4) Gross acres refer to the number of acres in which we own a working interest.
(5) Net acres represent the number of acres attributable to an owner's proportionate working interest in a lease (e.g., a 50% working interest in a lease covering 320 acres is equivalent to 160 net acres).

Included in the Offshore Gulf of Mexico acres shown in the table above are the beneficial interests Contango has in the offshore acreage owned by REX. The above table includes our 32.3% interest in REX's 1,163 net developed acres and 5,000 net undeveloped acres.

Productive Wells

The following table sets forth the number of gross and net productive natural gas and oil wells in which we owned an interest as of June 30, 2011:

	Total Productive Wells (1)	
	Gross (2)	Net (3)
Natural gas (onshore)	1	0.3
Natural gas (offshore)	13	6.5
Oil	-	-
Total	14	6.8

(1) Productive wells are producing wells and wells capable of producing commercial quantities. Completed but marginally producing wells are not considered here as a "productive" well.
(2) A gross well is a well in which we own an interest.
(3) The number of net wells is the sum of our fractional working interests owned in gross wells.

Natural Gas and Oil Reserves

The following table presents our estimated net proved natural gas and oil reserves and the pre-tax net present value of our reserves at June 30, 2011, based on reserve reports generated by William M. Cobb & Associates, Inc. ("Cobb"). The Company believes that having an independent and well respected third-party engineering firm prepare its reserve report enhances the credibility of its reported reserve estimates. Management is responsible for the reserve estimate disclosures in this filing, and meets regularly with our independent third-party engineer to review these reserve estimates. The qualifications of the technical person at Cobb responsible for overseeing the preparation of our reserve estimates are set forth below.

William M. Cobb & Associates, Inc.

- Over 30 years of practical experience in the estimation and evaluation of reserves
- A registered professional engineer in the state of Texas
- Bachelor of Science Degree in Petroleum Engineering
- Member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers

Cobb has informed us that the technical person primarily responsible for the reserve estimates meets or exceeds the education, training, and experience requirements set forth in the standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

We maintain adequate and effective internal controls over the underlying data upon which reserves estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information, which is communicated to our reservoir engineers quarterly, is confirmed when our third-party reservoir engineers hold technical meetings with geologists, operations and land personnel to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in Internal Controls – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. All data such as commodity prices, lease operating expenses, production taxes, field level commodity price differentials, ownership percentages, and well production data are updated in the reserve database by our third-party reservoir engineers and then analyzed by management to ensure that they have been entered accurately and that all updates are complete. Once the reserve database has been entirely updated with current information, and all relevant technical support material has been assembled, our independent engineering firms prepare their independent reserve estimates and final report.

	Total Proved Reserves as of June 30, 2011		
Offshore	**Developed**	**Undeveloped**	**Total**
Natural gas (MMcf)	205,085	33,060	238,145
Oil and condensate (MBbls)	3,738	740	4,478
Natural gas liquids (MBbls)	5,037	249	5,286
Total proved reserves (MMcfe)	257,735	38,994	296,729
Pre-tax net present value ($000) (discounted @ 10%)	$ 807,672	$ 173,369	$ 981,041

Prior Year Reserves

Our estimated net proved natural gas, oil and natural gas liquids reserves as of June 30, 2008, 2009 and 2010 are disclosed on page F-23 and were based on reserve reports generated by William M. Cobb & Associates, Inc. (“Cobb”). The reserve estimates as of June 30, 2010 also include the reserves associated with the Joint Venture Assets which were prepared exclusively by Lonquist & Co. LLC (“Lonquist”). These Joint Venture Asset reserves account for approximately 8% of our total reserves as of June 30, 2010 and were sold on May 13, 2011. The technical person at Lonquist responsible for overseeing the preparation of our Joint Venture Asset reserve estimates has over 22 years of practical experience in the estimation and evaluation of reserves, is a registered professional engineer in the state of Texas, has a BS in Petroleum Engineering, and is a member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. This individual meets or exceeds the education, training, and experience requirements set forth in the standards pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in the application of industry standard practices to engineering evaluations as well as the application of SEC and other industry definitions and guidelines.

Proved Undeveloped Reserves

The Company annually reviews any proved undeveloped reserves (“PUDs”) to ensure their development within five years or less. The Company had approximately 33 Bcf and 989 MBbls of PUDs, totaling 39 Bcfe at June 30, 2011. Of this amount, approximately 37.5 Bcfes are attributable to our discovery at Vermilion 170 that will begin producing in September 2011. Our plan is to develop the remaining PUD opportunities prior to June 30, 2016. At June 30, 2010 the Company had 19.8 Bcfe of PUDs mainly related to Cotton Valley and Travis Peak gas reserves in Panola County, Texas under our joint venture with Patara. These PUDs were sold on May 13, 2011 and the transaction is classified as discontinued operations in our financial statements. The Company had no PUDs at June 30, 2009.

Modernization of Oil and Gas Reporting

In December 2008, the SEC released the final rule for *Modernization of Oil and Gas Reporting*. The new rule requires disclosure of oil and gas proved reserves using the 12-month average beginning-of-month price for the year, rather than year-end prices, and allows the use of reliable technologies to estimate proved oil and gas reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. In addition, companies are required to report on the independence and qualifications of its reserves preparer or auditor, and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. The reserves information above is presented consistent with the requirements of the new rule. The new rule does not allow prior-year reserve information to be restated, so all information related to periods prior to June 30, 2010 is presented consistent with prior SEC rules for the estimation of proved reserves. In January 2010, the Financial Accounting Standards Board ("FASB") adopted the SEC's final rule for *Modernization of Oil and Gas Reporting.*

The line item "Pre-tax net present value, discounted at 10%" in the table above, is not intended to represent the current market value of the estimated natural gas and oil reserves we own. The pre-tax net present value of future cash flows attributable to our proved reserves as of June 30, 2011 was based on $4.25 per million British thermal units ("MMbtu") for natural gas at the NYMEX, $90.27 per barrel of oil at the West Texas Intermediate Posting, and $55.78 per barrel of NGLs, in each case before adjusting for basis, transportation costs and British thermal unit ("BTU") content. The pre-tax net present value is a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K. The table below reconciles our calculation of pre-tax net present value to the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Management believes that pre-tax net present value is an important non-GAAP financial measure used by analysts, investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The reconciliation of the pre-tax net present value to the standardized measure of discounted future net cash flows relating to our proved oil and natural gas reserves at June 30, 2011 is as follows (in thousands):

		June 30, 2011
Pre-tax net present value ($000) (discounted @ 10%)	$	981,041
Future income taxes, discounted at 10%.......................................		(263,906)
Standardized measure of discounted future net cash flows...........	$	717,135

While we are reasonably certain of recovering our calculated reserves, the process of estimating natural gas and oil reserves is complex. It requires various assumptions, including natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Our third party engineers must project production rates, estimate timing and amount of development expenditures, analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of all of this data may vary. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from estimates. Any significant variance could materially affect the estimated quantities and net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

Item 3. *Legal Proceedings*

From time to time, we are party to litigation or other legal and administrative proceedings that we consider to be a part of the ordinary course of business. As of the date of this Form 10-K, we are not a party to any material legal proceedings and we are not aware of any material proceedings contemplated against us, that could individually or in the aggregate, reasonably be expected to have a material adverse effect on our financial condition, cash flows or results of operations.

Item 4. *Reserved*

PART II

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

Our common stock was listed on the NYSE Amex (previously the American Stock Exchange) in January 2001 under the symbol "MCF". The table below shows the high and low closing prices of our common stock for the periods indicated.

	High	Low
Fiscal Year 2010:		
Quarter ended September 30, 2009	$ 51.06	$ 40.40
Quarter ended December 31, 2009	$ 54.09	$ 44.38
Quarter ended March 31, 2010	$ 55.00	$ 47.07
Quarter ended June 30, 2010	$ 60.03	$ 44.28
Fiscal Year 2011:		
Quarter ended September 30, 2010	$ 51.28	$ 41.40
Quarter ended December 31, 2010	$ 59.91	$ 50.30
Quarter ended March 31, 2011	$ 63.24	$ 55.02
Quarter ended June 30, 2011	$ 64.19	$ 55.12

On August 26, 2011, the closing price of our common stock on the NYSE Amex was $58.35 per share, and there were 15,627,966 shares of Contango common stock outstanding.

We have not declared or paid any cash dividends on our shares of common stock. Any future decision to pay dividends on our common stock will be at the discretion of our board and will depend upon our financial condition, results of operations, capital requirements, and other factors our board may deem relevant.

The following table sets forth information about our equity compensation plans at June 30, 2011:

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (b))
1999 Stock Incentive Plan - approved by security holders	45,000	$54.21	-
2009 Equity Compensation Plan - approved by security holders	-	-	1,475,000
Equity compensation plans not approved by security holders	-	-	-

The Company's 1999 Stock Incentive Plan (the "1999 Plan") expired in August 2009. There are 45,000 outstanding options issued under the 1999 Plan which will be converted into securities if exercised prior to their expiration in September 2013.

On September 15, 2009, the Company's Board of Directors (the "Board") adopted the Contango Oil & Gas Company Equity Compensation Plan (the "2009 Plan"), which was approved by shareholders on November 19, 2009. Under the 2009 Plan, the Board may grant restricted stock and option awards to officers, directors, employees or consultants of the Company. Awards made under the 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board. As of August 24, 2011, all options issued under the 2009 Plan had been exercised. The Company has not issued any restricted stock under the 2009 Plan.

During the fiscal year ended June 30, 2011, the Company purchased 172,544 shares of its common stock. Of this amount, 152,544 shares were purchased from three officers of the Company, one member of the Board, one employee, and one consultant for approximately $8.9 million. During the fiscal year ended June 30, 2010, the Company purchased 115,454 shares of its common stock from three officers of the Company and two members of the Board for approximately $6.4 million. During the fiscal year ended June 30, 2009, the Company purchased 21,754 shares of its common stock from one member of the Board for approximately $1.3 million. All purchases were approved by the Board under the Company's share repurchase program and were completed at the closing price of the Company's common stock on the date of purchase.

Share Repurchase Program

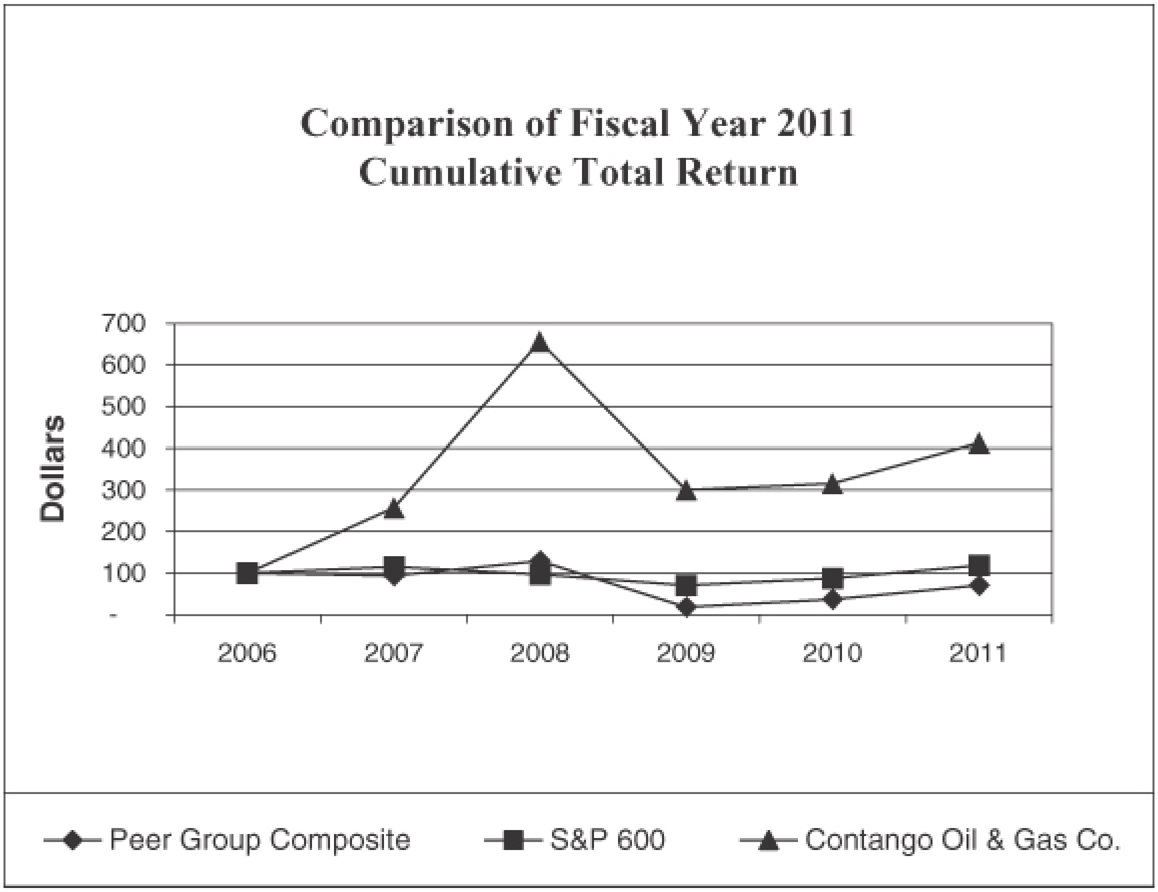
In September 2008, the Company's board of directors approved a $100 million share repurchase program. Under the program, all shares are purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases will be made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes. During the fiscal year ended June 30, 2011, the Company purchased the below listed shares under its share repurchase program, resulting in 15,664,666 shares of common stock outstanding and 45,000 options outstanding as of June 30, 2011.

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under Program
July 6 - July 7, 2010	20,000	$ 43.26	1,732,897	$ 23.9 million
November 19, 2010	150,967	$ 58.35	1,883,864	$ 15.1 million
December 23, 2010	1,577	$ 59.91	1,885,441	$ 15.0 million

The 152,544 shares of common stock purchased on November 19 and December 23 were issued as a result of a cashless exercise of stock options. A total of 107,790 shares were surrendered by the option holders to obtain the 152,544 shares that were sold to the Company. As a result of these two transactions, the Company retired a total of 260,334 shares and options.

Additionally, on August 22 and 23, 2011, the Company purchased an additional 36,700 shares at an average price of $54.91. As a result, as of August 26, 2011, the Company has 15,627,966 shares of common stock outstanding and 45,000 options outstanding.

The following graph compares the yearly percentage change from June 30, 2006 until June 30, 2011 in the cumulative total stockholder return on our common stock to the cumulative total return on the S&P Smallcap 600 Index and a peer group of five independent oil and gas exploration companies selected by us. The companies in our selected peer group are ATP Oil & Gas Corp., Callon Petroleum, Energy XXI (Bermuda) Limited, McMoRan Exploration Company, and W&T Offshore, Inc. Our common stock began trading on the NYSE Amex (previously American Stock Exchange) on January 19, 2001 and before that traded on the Nasdaq over-the-counter Bulletin Board. The graph assumes that a $100 investment was made in our common stock and each index on June 30, 2006 and that all dividends were reinvested. The stock performance for our common stock is not necessarily indicative of future performance. For companies that did not exist as of June 30, 2006, we used the initial public price for all periods that an actual price did not exist.



	6/30/2006	6/30/2007	6/30/2008	6/30/2009	6/30/2010	6/30/2011
Peer Group Composite	100	94	129	19	37	70
S&P 600	100	115	97	71	87	118
Contango Oil & Gas Co.	100	257	657	300	316	413

Item 6. ***Selected Financial Data***

The selected consolidated financial data (not including proved reserve information) set forth below is for continuing operations and should be read in conjunction with Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with the consolidated financial statements and notes to those consolidated financial statements included elsewhere in this Form 10-K.

	Year Ended June 30,				
	2011	2010	2009	2008	2007
Financial Data:	(Dollar amounts in 000s, except per share amounts)				
Revenues:					
Natural gas and oil sales	$ 203,778	$ 159,010	$ 190,656	$ 116,498	$ 14,140
Total revenues.	$ 203,778	$ 159,010	$ 190,656	$ 116,498	$ 14,140
Income (loss) from continuing operations	$ 63,452	$ 50,166	$ 55,861	$ 83,221	$ (1,078)
Discontinued operations, net of income taxes	1,581	(480)	-	173,685	(1,617)
Net income (loss)	$ 65,033	$ 49,686	$ 55,861	$ 256,906	$ (2,695)
Preferred stock dividends	-	-	-	1,548	540
Net income (loss) attributable to common stock	$ 65,033	$ 49,686	$ 55,861	$ 255,358	$ (3,235)
Net income (loss) per share:					
Basic					
Continuing operations	$ 4.05	$ 3.17	$ 3.41	$ 5.05	$ (0.03)
Discontinued operations	0.10	(0.03)	-	10.73	(0.18)
Total	$ 4.15	$ 3.14	$ 3.41	$ 15.78	$ (0.21)
Diluted					
Continuing operations	$ 4.04	$ 3.11	$ 3.35	$ 4.82	$ (0.03)
Discontinued operations	0.10	(0.03)	-	10.06	(0.18)
Total	$ 4.14	$ 3.08	$ 3.35	$ 14.88	$ (0.21)
Weighted average shares outstanding:					
Basic	15,665	15,831	16,363	16,185	15,430
Diluted	15,713	16,157	16,690	17,263	15,430
Working capital (deficit)	$ 126,654	$ 41,385	$ 43,232	$ 29,913	$ (4,088)
Capital expenditures	$ 69,904	$ 97,699	$ 45,742	$ 119,929	$ 77,688
Long term debt	$ -	$ -	$ -	$ 15,000	$ 20,000
Stockholders' equity	$ 426,623	$ 377,330	$ 349,364	$ 341,998	$ 90,804
Total assets	$ 636,930	$ 592,266	$ 517,042	$ 599,974	$ 153,936
Proved Reserve Data:					
Total proved reserves (Mmcfe)	296,729	314,027	355,046	369,076	84,876
Pre-tax net present value (discounted at 10%)	$ 981,041	$ 970,442	$ 889,865	$ 3,183,843	$ 329,179
Standardized Measure	$ 717,135	$ 712,094	$ 638,091	$ 2,233,918	$ 252,297

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 the financial statements and the related notes and other information included elsewhere in this report.

Overview

Contango is a Houston-based, independent natural gas and oil company. The Company's business is to explore, develop, produce and acquire natural gas and oil properties primarily offshore in the shallow waters of the Gulf of Mexico in water-depths of less than 300 feet. COI, our wholly-owned subsidiary, acts as operator on certain offshore prospects.

Revenues and Profitability. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil and on our ability to find, develop and acquire natural gas and oil reserves that are economically recoverable. The preparation of our financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved natural gas and oil reserves. We use the successful efforts method of accounting for our natural gas and oil activities.

Reserve Replacement. Generally, our producing properties offshore in the Gulf of Mexico have high initial production rates, followed by steep declines. As a result, we must locate and develop or acquire new natural gas and oil reserves to replace those being depleted by production. Substantial capital expenditures are required to find, develop and acquire natural gas and oil reserves.

Sale of proved properties. From time-to-time as part of our business strategy, we have sold, and in the future may continue to sell some or a substantial portion of our proved reserves to capture current value, using the sales proceeds to reduce debt and further our exploration activities.

Use of Estimates. The preparation of our financial statements requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates. Significant estimates with regard to these financial statements include estimates of remaining proved natural gas and oil reserves, the timing and costs of our future drilling, development and abandonment activities, and income taxes.

See "Risk Factors" on page 13 for a more detailed discussion of a number of other factors that affect our business, financial condition and results of operations.

Impact of Deepwater Horizon Incident and Federal Deepwater Moratorium

In April 2010, the deepwater Gulf of Mexico drilling rig Deepwater Horizon, engaged in drilling operations for another operator, sank after an apparent blowout and fire. In response, the Secretary of the Interior required all drilling operations in the Gulf of Mexico to stop until operators certify that they have adequate plans in place to quickly shut down an out-of-control well, that the blowout preventers atop the wells it drills have passed rigorous new tests, and that sufficient cleanup resources are on hand in the event of a spill.

Business Impact

We believe that the Deepwater Horizon incident will have a significant and lasting effect on the U.S. offshore energy industry, and will result in a number of fundamental changes, including heightened regulatory scrutiny, more stringent operating and safety standards, changes in equipment requirements and the availability and cost of insurance, as well as increased politicization of the industry. A significant delay of planned exploratory activities will reduce our longer term ability to replace reserves, resulting in a negative impact on production, including a reduction in operating results and cash flows as we deplete our reserves. There may be other impacts of which we are not aware at this time.

Finally, the potential for removal of the liability cap for claims of damages from oil spills, and/or the enactment of onerous rules and regulations regarding activities in the Gulf of Mexico could significantly alter our industry. Such rules could effectively limit which companies can operate in the Gulf of Mexico. Small and medium-sized oil and gas companies may not be able to obtain insurance coverage at economically appropriate levels or meet financial responsibility requirements and would be forced to exit operations in the Gulf of Mexico. Potentially less attractive economics for exploration and development programs going forward will require companies retaining operations in the Gulf of Mexico to review their business models. We have drilled, and believe we can continue to drill, safely in the Gulf of Mexico. However, exploration and production companies will be able to continue doing business in the Gulf of Mexico only to the extent it remains economically viable.

Delays and volatility are inherent in our business. We have maintained a capital structure with a strong liquidity position allowing us to manage during periods of uncertainty. We believe we are well-positioned to respond to the increasingly complex regulatory framework for the Gulf of Mexico.

Results of Operations

The following is a discussion of the results of our continuing operations for the fiscal year ended June 30, 2011, compared to the fiscal year ended June 30, 2010, and for the fiscal year ended June 30, 2010, compared to the fiscal year ended June 30, 2009.

Revenues. All of our revenues are from the sale of our natural gas and oil production. Our revenues may vary significantly from year to year depending on changes in commodity prices, which fluctuate widely, and production volumes. Our production volumes are subject to wide swings as a result of new discoveries, weather and mechanical related problems. In addition, our production declines over time as we produce our reserves.

The table below sets forth revenue and production data for continuing operations for the fiscal years ended June 30, 2011, 2010 and 2009.

	Year ended June 30,			Year ended June 30,		
	2011	**2010**	**%**	**2010**	**2009**	**%**
Revenues:	($000)			($000)		
Natural gas and oil sales	$ 203,778	$ 159,010	28%	$ 159,010	$ 190,656	-17%
Total revenues	$ 203,778	$ 159,010		$ 159,010	$ 190,656	
Production:						
Natural gas (million cubic feet)	24,742	21,081	17%	21,081	20,535	3%
Oil and condensate (thousand barrels)	675	504	34%	504	515	-2%
Natural gas liquids (thousand gallons)	26,926	24,690	9%	24,690	24,803	*
Total (million cubic feet equivalent)	32,639	27,632	18%	27,632	27,168	2%
Natural gas (million cubic feet per day)	67.8	57.8	17%	57.8	56.3	3%
Oil and condensate (thousand barrels per day)	1.8	1.4	29%	1.4	1.4	*
Natural gas liquids (thousand gallons per day)	73.8	67.6	9%	67.6	68.0	*
Total (million cubic feet equivalent per day)	89.1	75.9	17%	75.9	74.4	2%
Average Sales Price:						
Natural gas (per thousand cubic feet)	$ 4.39	$ 4.48	-2%	$ 4.48	$ 6.34	-29%
Oil and condensate (per barrel)	$ 91.97	$ 77.18	19%	$ 77.18	$ 67.72	14%
Natural gas liquids (per gallon)	$ 1.23	$ 1.04	18%	$ 1.04	$ 1.03	*
Total (per thousand cubic feet equivalent)	$ 6.24	$ 5.75	9%	$ 5.75	$ 7.02	-18%
Operating expenses	$ 25,989	$ 16,692	56%	$ 16,692	$ 23,684	-30%
Exploration expenses	$ 9,751	$ 20,850	-53%	$ 20,850	$ 20,603	1%
Depreciation, depletion and amortization	$ 55,231	$ 34,521	60%	$ 34,521	$ 32,673	6%
Impairment of natural gas and oil properties	$ 1,786	$ 952	88%	$ 952	$ 11,075	-91%
General and administrative expenses	$ 12,341	$ 4,599	168%	$ 4,599	$ 9,467	-51%
Other income (expense).	$ (158)	$ 398	-140%	$ 398	$ 184	116%
Gain (loss) on sale of assets and other	$ (273)	$ 113	-342%	$ 113	$ (530)	121%

* less than 1%

Natural Gas, Oil and NGL Sales. We reported revenues of approximately $203.8 million for the year ended June 30, 2011, up from approximately $159.0 million reported for the year ended June 30, 2010. This increase in sales was primarily attributable to increased natural gas and oil sales from our Ship Shoal 263 well which began producing in June 2010; our Eloise South well (now our Dutch #5 well) which began producing in July 2010; and our Rexer #1 well which began producing in October 2010 (our Rexer #1 well was sold effective April 1, 2011. See "Property Sales and Discontinued Operations" earlier for more information). Also contributing to the increase in sales was an increase in oil and NGL prices received for the year ended June 30, 2011, as well as increased production from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days during fiscal year 2010 due to our ruptured 20" pipeline. This increase in sales was partially offset by a decrease in natural gas prices, and shutting in our Eloise South well in October 2010 and our Eloise North well in February 2011 for remedial work. Both wells have since resumed production.

We reported revenues of approximately $159.0 million for the year ended June 30, 2010, down from approximately $190.7 million reported for the year ended June 30, 2009. This decrease in sales was primarily attributable to the significant decline in natural gas prices received for the year ended June 30, 2010. Also contributing was a reduction in production as a result of our ruptured 20" pipeline which shut-in production from our four Mary Rose wells, Dutch #4 and our Eloise North wells for approximately 35 days in fiscal year 2010. This decreased production was partially offset by increased production from our Eloise North well which began producing in December 2008 and our Dutch #4 well which began producing in January 2009. The decrease in production was also offset by increased production from our Dutch #1, #2 and #3 wells which increased production in fiscal year 2010, as compared to prior year when they were shut-in during all of September, October and the majority of November 2008 due to Hurricane Ike.

Average Sales Prices. For the year ended June 30, 2011, the price of natural gas was $4.39 per Mcf while the price for oil and NGLs was $91.97 per barrel and $1.23 per gallon, respectively. For the year ended June 30, 2010, the price of natural gas was $4.48 per Mcf while the price for oil and NGLs was $77.18 per barrel and $1.04 per gallon, respectively. For the year ended June 30, 2009, the price of natural gas was $6.34 per Mcf while the price for oil and NGLs was $67.72 per barrel and $1.03 per gallon, respectively.

Natural Gas, Oil and NGL Production. Our net natural gas production for the year ended June 30, 2011 was approximately 67.8 Mmcfd, up from approximately 57.8 Mmcfd for the year ended June 30, 2010. Net oil production and NGL production also increased for the comparable periods. Net oil production increased from 1,400 bopd to 1,800 bopd, while NGL production increased from approximately 67,600 gallons per day to 73,800 gallons per day. This increase in natural gas, oil and NGL production was principally attributable to our Ship Shoal 263 well which began producing in June 2010; our Eloise South well (now our Dutch #5 well) which began producing in July 2010; and our Rexer #1 well which began producing in October 2010 (our Rexer #1 well was sold effective April 1, 2011. See "Property Sales and Discontinued Operations" earlier for more information). Also contributing to the increase in production was increased production from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days during fiscal year 2010 due to our ruptured 20" pipeline. This increase in production was partially offset by shutting in our Eloise South well in October 2010 and our Eloise North well in February 2011 for remedial work. Both wells have since resumed production.

Our net natural gas production for the year ended June 30, 2010 was approximately 57.8 Mmcfd, up from approximately 56.3 Mmcfd for the year ended June 30, 2009. Net oil production and NGL production remained relatively stable for the comparable periods. Net oil production remained flat at approximately 1,400 bopd for both periods, while NGL production went from approximately 68,000 gallons per day to approximately 67,600 gallons per day. This increase in natural gas production was principally attributable to our Eloise North well which began producing in December 2008 and our Dutch #4 well which began producing in January 2009. The increase in production was also attributable to our Dutch #1, #2 and #3 wells which were shut-in during all of September, October and the majority of November 2008 due to Hurricane Ike. This increase in production was partially offset by our ruptured 20" pipeline which shut-in production from our four Mary Rose wells, Dutch #4 and our Eloise North wells for approximately 35 days in 2010.

Operating Expenses. Operating expenses for the year ended June 30, 2011 were approximately $26.0 million, which included approximately $4.6 million in Louisiana state severance taxes, $1.7 million in workover costs, and $4.6 million of well insurance. The remaining $15.1 million related to lease operating expenses for 11 offshore wells and one onshore well, compared to operating expenses for the year ended June 30, 2010 of approximately $16.7 million, which included approximately $5.3 million of Louisiana state severance taxes and $0.7 million in workover costs. The remaining $10.7 million related to lease operating expenses for nine offshore wells. Operating expenses for the year ended June 30, 2009 were approximately $23.7 million which included approximately $3.7 million in Louisiana severance taxes and $10.7 million for workover costs. The remaining $9.3 million related to lease operating expenses for seven offshore wells, plus an additional two wells that were only producing for a portion of the year.

Exploration Expenses. We reported approximately $9.8 million of exploration expenses for the year ended June 30, 2011. Of this amount, approximately $9.5 million related to our dry hole at Galveston Area 277L, and the remaining $0.3 million related to various geological and geophysical activities, seismic data, and delay rentals.

We reported approximately $20.9 million of exploration expenses for the year ended June 30, 2010. Of this amount, approximately $14.9 million related to the dry hole the Company drilled at Matagorda Island 617, $5.3 million related to the dry hole the Company drilled at Vermillion 155, and the remaining $0.7 million related to various geological and geophysical activities, seismic data and delay rentals.

We reported approximately $20.6 million of exploration expenses for the year ended June 30, 2009. Of this amount, approximately $7.1 million related to the dry hole the Company drilled at West Delta 77, $12.5 million related to the dry hole the Company drilled at Eugene Island 56, and the remaining $1.0 million related to various geological and geophysical activities, seismic data and delay rentals.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization for the year ended June 30, 2011 was approximately $55.2 million. This compares to approximately $34.5 million for the year ended June 30, 2010. The increase in depreciation, depletion and amortization was primarily attributable to an overall increase in production and increase in capitalized costs as a result of our Ship Shoal 263, Eloise South and Rexer #1 discoveries. Also contributing to the increase in depreciation, depletion and amortization were increased produced volumes from our four Mary Rose wells, Dutch #4 and our Eloise North wells, which were shut-in for approximately 35 days in 2010 due to our ruptured 20” pipeline. This increase in depreciation, depletion and amortization was partially offset by shutting in our Eloise South well in October 2010 and our Eloise North well in February 2011 for remedial work.

Depreciation, depletion and amortization for the year ended June 30, 2010 was approximately $34.5 million, compared to $32.7 million for the year ended June 30, 2009. The increase in depreciation, depletion and amortization was primarily attributable to an overall increase in production from our Eloise North and Dutch #4 wells, an increase in production from our Dutch #1, #2 and #3 wells which were shut-in during three months in fiscal year 2009 due to Hurricane Ike, and an increase in reserves due to new discoveries. This increase in production was partially offset by our ruptured 20” pipeline which shut-in production from our Mary Rose wells, Dutch #4 and Eloise North wells for approximately 35 days in fiscal year 2010, as well as by a downward revision of our reserves in June 2010.

Impairment of Natural Gas and Oil Properties. For the year ended June 30, 2011, the Company recorded impairment expense of approximately $1.8 million related to the relinquishment of 14 lease blocks owned by Contango and REX. For the year ended June 30, 2010, the Company recorded impairment expense of approximately $1.0 million, related to the relinquishment of six lease blocks owned by REX and COE.

For the year ended June 30, 2009, the Company recorded impairment expense of approximately $11.1 million. Of this amount, approximately $5.2 million was due to the expiration and relinquishment of 44 lease blocks owned by REX and COE; $2.5 million related to the impairment of Grand Isle 70; and $3.4 million related to the impairment of Grand Isle 72.

General and Administrative Expenses. General and administrative expenses for the year ended June 30, 2011 were approximately $12.3 million, up from approximately $4.6 million for the year ended June 30, 2010. The increase is principally attributable to higher bonus payments and stock option expenses in the year ended June 30, 2011. Major components of general and administrative expenses for the year ended June 30, 2011 included approximately $9.6 million in salaries, bonuses, stock-based compensation, benefits and board compensation (includes $1.3 million in non-cash expenses related to option awards), $0.9 million in office administration and other expenses, $0.5 million in insurance costs, $0.5 million in accounting and tax services, and $0.8 million in legal, consulting and other administrative expenses.

General and administrative expenses for the year ended June 30, 2010 were approximately $4.6 million, down from approximately $9.5 million for the year ended June 30, 2009. The decrease is principally attributable to lower bonus payments and stock and stock option expenses in the year ended June 30, 2010. Major components of general and administrative expenses for the year ended June 30, 2010 included approximately $3.0 million in salaries, stock-based compensation, benefits and board compensation (includes $0.7 million in non-cash expenses related to restricted stock and option awards), $0.5 million in office administration and other expenses, $0.5 million in insurance costs, $0.2 million in accounting and tax services, and $0.4 million in legal, consulting and other administrative expenses.

General and administrative expenses for the year ended June 30, 2009 were approximately $9.5 million. Major components of general and administrative expenses for the year ended June 30, 2009 included approximately $5.3 million in salaries, benefits and bonuses (includes $1.4 million in non-cash expenses related to restricted stock and option awards), $1.7 million in office administration and other expenses, $0.5 million in insurance costs, $0.7 million in accounting and tax services, and $1.3 million in legal and other administrative expenses.

Other Income (Expense). We reported other expense of approximately $0.2 million for the fiscal year ended June 30, 2011, compared to other income of approximately $0.4 million and $0.2 million for the fiscal years ended June 30, 2010 and 2009, respectively. This item is a combination of interest income and interest expense. The higher levels of interest income for the fiscal years ended 2010 and 2009 relate mainly to interest income on the COE Note.

Gain on Sale of Assets and Other. For the fiscal year ended June 30, 2011, we reported a loss on sale of assets of approximately $0.3 million related to the sale of Rexer #1 and 75% of Rexer-Tusa #2. For the year ended June 30, 2010, we reported a gain on sale of assets of approximately $0.1 million related to the sale of our Grand Isle 70 well. For the year ended June 30, 2009, we reported a loss on sale of assets of approximately $0.5 million related to a post-closing adjustment for the sale of our Arkansas Fayetteville Shale properties.

Discontinued Operations. The table and discussions above, along with our financial statements, discuss only continuing operations for all fiscal years presented. Not reflected are the Company's sold producing properties which generated approximately 4.0% of combined revenues for the fiscal year ended June 30, 2011. See Note 6 – Discontinued Operations of Notes to Consolidated Financial Statements included as part of this Form 10-K, for a discussion of our discontinued operations.

Capital Resources and Liquidity

Cash From Operating Activities. Cash flow from operating activities provided approximately $140.6 million in cash for the year ended June 30, 2011 compared to $128.2 million for the same period in 2010. This increase in cash provided by operating activities was primarily attributable to increased sales due to increased natural gas, oil and NGL production attributable to our Ship Shoal 263 and Eloise South (now Dutch #5) wells, as well as from other wells which were shut-in for approximately 35 days in fiscal year 2010.

Cash flow from operating activities provided approximately $128.2 million in cash for the year ended June 30, 2010 compared to $95.4 million for the same period in 2009. This increase in cash provided by operating activities was primarily attributable to increased natural gas, oil and NGL production attributable to our Eloise North and Dutch #4 well. The increase in production was also attributable to our Dutch #1, #2 and #3 wells which were shut-in during all of September, October and the majority of November 2008 due to Hurricane Ike.

Cash From Investing Activities. Cash flow used in investing activities for the year ended June 30, 2011 was approximately $33.3 million, compared to $97.7 million used in investing activities for the year ended June 30, 2010. The lower level of cash flows used in investing activities in 2011 was primarily attributable to decreased capital expenditures for drilling exploration and development wells as well as $38.7 million received from the sale of oil and gas properties.

Cash flows used in investing activities for the year ended June 30, 2010 were approximately $97.7 million, compared to $45.8 million used in investing activities for the year ended June 30, 2009. The higher level of cash flows used in investing activities in 2010 was primarily attributable to increased capital expenditures for drilling exploration and development wells.

Cash From Financing Activities. Cash flows used in financing activities for the year ended June 30, 2011 were approximately $9.8 million, compared to $22.4 million used in financing activities for the same period in 2010. During the fiscal year ended June 30, 2011, the Company did not repurchase as many shares of its common stock pursuant to its share repurchase program, as it did in for the fiscal year ended June 30, 2010.

Cash flows used in financing activities for the year ended June 30, 2010 were approximately $22.4 million, compared to $65.1 million used in financing activities for the same period in 2009. This $65.1 million of cash flows used in financing activities for the year ended June 30, 2009 is primarily composed of purchasing approximately $51.8 million of our common stock and the repayment of $15.0 million of debt. There were no credit facility payments and fewer purchases of common stock during the year ended June 30, 2010.

Income Taxes. During the year ended June 30, 2011, 2010 and 2009, we paid approximately $31.9 million, $11.5 million, and $45.6 million, respectively, in federal and state income taxes, net of refunds received.

Capital Budget. For the remainder of fiscal year 2012, our capital expenditure budget calls for us to invest approximately $81.4 million from cash flow from operations and cash on hand as follows:

- We have budgeted to invest approximately $5.5 million to complete building the facilities for our Vermilion 170 discovery and begin production.
- We have budgeted to invest approximately $5.6 million to complete payment of the recompletion of our Eloise South well up hole.

- We have budgeted to invest approximately $0.4 million to complete payment of the workover on our Eloise North well.
- We have budgeted to invest approximately $0.3 million to complete payment of completion costs on our Rexer-Tusa #2 well.
- We have budgeted to invest approximately $25.0 million to drill our Ship Shoal 121/134 (“Eagle”) prospect.
- We have budgeted to invest approximately $25.0 million to drill our South Timbalier 75 (“Fang”) prospect.
- We have budgeted to invest approximately $19.6 million in Alta Energy.

Should we be successful in any of our offshore prospects, we will have the opportunity to spend significantly more capital to complete development and bring the discovery to producing status. The Company often reviews acquisitions and prospects presented to us by third parties and may decide to invest in one or more of these opportunities. There can be no assurance that we will invest, or that any investment entered into will be successful. These potential investments are not part of our current capital budget and would require us to invest additional capital. Natural gas and oil prices continue to be volatile and our resources may be insufficient to fund any of these opportunities. As of August 24, 2011, we had approximately $135 million in cash and cash equivalents and no debt outstanding.

Discontinued Operations. The Company, since its inception in September 1999, has raised approximately $524 million in proceeds from property sales, and views periodic reserve sales as an opportunity to capture value, reduce reserve and price risk, in addition to being a source of funds for potentially higher rate of return natural gas and oil exploration investments. We believe these periodic natural gas and oil property sales are an efficient strategy to meet our cash and liquidity needs by providing us with immediate cash, which would otherwise take years to realize through the production lives of the fields sold. We have in the past and expect to in the future to continue to rely heavily on the sales of assets to generate cash to fund our exploration investments and operations.

These sales bring forward future revenues and cash flows, but our longer term liquidity could be impaired to the extent our exploration efforts are not successful in generating new discoveries, production, revenues and cash flows. Additionally, our longer term liquidity could be impaired due to the decrease in our inventory of producing properties that could be sold in future periods. Further, as a result of these property sales the Company’s ability to collateralize bank borrowings is reduced which increases our dependence on more expensive mezzanine debt and potential equity sales. The availability of such funds will depend upon prevailing market conditions and other factors over which we have no control, as well as our financial condition and results of operations.

The table below sets forth the proceeds received from natural gas and oil property sales for the year ended June 30, 2011, the impact of these sales on our developed reserve quantities, and a measure of our developed reserves held at the end of each such fiscal year. See the reserve activity reported in the Supplemental Oil and Gas Disclosures on pages F-22 through F-25 for a more detailed discussion regarding our standardized measure.

Fiscal Year of Property Sale	Proceeds Received	Reserves Sold (Bcfe)	Reserves at end of Fiscal Year (Bcfe)	Standardized Measure of Discounted Future Net Cash Flows at end of Fiscal Year (’000)
2011	$ 38.7 million	17.2	296.7	$ 717,360

For fiscal year 2011 and 2010, the Company realized approximately $4.8 million and $(0.2) million in operating cash flows from discontinued operations, approximately $10.8 million and $(20.9) million in investing cash flows from discontinued operations and approximately $(15.6) million and $21.1 million in financing cash flows from discontinued operations.

Off Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our known contractual obligations as of June 30, 2011:

	Payment due by period ($000)				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long term debt	$ -	$ -	$ -	$ -	$ -
Delay rentals	531	165	261	105	-
Asset retirement obligations.	8,611	-	-	-	8,611
Operating leases	1,121	244	502	375	-
Total	$ 10,263	$ 409	$ 763	$ 480	$ 8,611

In addition, the Company pays a commitment fee of 0.375% on the unused borrowing capacity of our $40 million credit facility with Amegy Bank (See "Credit Facility" below), and we have committed to invest up to an additional $19.6 million over the next two years in Alta Energy to acquire, explore, develop and operate onshore unconventional shale operated and non-operated oil and natural gas assets.

Credit Facility

On October 22, 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the "Credit Agreement") to replace the expiring credit agreement with BBVA Compass Bank. The Credit Agreement currently has a $40 million hydrocarbon borrowing base and will be available to fund the Company's offshore Gulf of Mexico exploration and development activities, as well as the repurchase of shares of common stock of the Company and to fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. The principal is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of $300,000 was paid in connection with the facility and a commitment fee of 0.375% will be paid on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of the date of this report, the Company was in compliance with all covenants and had no amounts outstanding under the Credit Agreement.

Application of Critical Accounting Policies and Management's Estimates

The discussion and analysis of the Company's financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. The Company's significant accounting policies are described in Note 2 of Notes to Consolidated Financial Statements included as part of this Form 10-K. We have identified below the policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. The Company analyzes its estimates, including those related to natural gas and oil reserve estimates, on a periodic basis and bases its estimates on historical experience, independent third party reservoir engineers and various other assumptions that management believes to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of the Company's consolidated financial statements:

Successful Efforts Method of Accounting. Our application of the successful efforts method of accounting for our natural gas and oil exploration and production activities requires judgments as to whether particular wells are developmental or exploratory, since exploratory costs and the costs related to exploratory wells that are determined to not have proved reserves must be expensed whereas developmental costs are capitalized. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver natural gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive natural gas and oil field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory.

Reserve Estimates. While we are reasonably certain of recovering our reported reserves, the Company’s estimates of natural gas and oil reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable natural gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future natural gas and oil prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future development costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected natural gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company’s natural gas and oil properties and/or the rate of depletion of such natural gas and oil properties. In June 2010, the Company revised its offshore reserves downward by approximately 48.5 Bcfe. This revision was attributable to newly obtained bottom hole pressure data as a result of a recent field wide shut-in and a “P/Z pressure test” that indicated fewer reserves than was originally estimated.

Actual production, revenues and expenditures with respect to the Company’s reserves will likely vary from estimates, and such variances may be material. Holding all other factors constant, a reduction in the Company’s proved reserve estimate at June 30, 2011 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $2.9 million, $6.2 million, and $9.8 million, respectively.

Impairment of Natural Gas and Oil Properties. The Company reviews its proved natural gas and oil properties for impairment whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. The Company compares expected undiscounted future net cash flows from each field to the unamortized capitalized cost of the asset. If the future undiscounted net cash flows, based on the Company’s estimate of future natural gas and oil prices and operating costs and anticipated production from proved reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to fair market value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates, and anticipated capital expenditures. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Drilling activities in an area by other companies may also effectively condemn leasehold positions. Given the complexities associated with natural gas and oil reserve estimates and the history of price volatility in the natural gas and oil markets, events may arise that will require the Company to record an impairment of its natural gas and oil properties and there can be no assurance that such impairments will not be required in the future nor that they will not be material.

Income Taxes. Income taxes are provided for the tax effects of transactions reported in the financial statements and consists of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income taxes are measured by applying currently enacted tax rates to the differences between financial statements and income tax reporting. Numerous judgments and assumptions are inherent in the determination of deferred income tax assets and liabilities as well as income taxes payable in the current period. We are subject to taxation in several jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions.

Recent Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2011-05: *Comprehensive Income (Topic 220): Presentation of Comprehensive Income* (ASU 2011-05). ASU 2011-05 provides that an entity that reports items of other comprehensive income has the option to present comprehensive income in either one continuous financial statement or two consecutive financial statements. ASU 2011-05 is effective for annual periods beginning after December 15, 2011. We do not expect its implementation to have any effect on our financial position or results of operations.

In May 2011, the FASB issued Accounting Standards Update No. 2011-04: *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU

2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual periods beginning after December 15, 2011. We are currently evaluating the provisions of ASU 2011-04 and assessing the impact, if any, it may have on our financial position and results of operations.

On January 1, 2011, we implemented certain provisions of Accounting Standards Update No. 2010-06: *Fair Value Measurements and Disclosures (Topic 820) – Improving Disclosures about Fair Value Measurements* (ASU 2010-06). ASU 2010-06 requires entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on our consolidated results of operations, financial position or cash flows.

Item 7A. *Quantitative and Qualitative Disclosure about Market Risk*

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas and oil production. Realized commodity prices received for our production are tied to the spot prices applicable to natural gas and crude oil at the applicable delivery points. Prices received for natural gas and oil are volatile and unpredictable. We do not hedge against price risk exposure. For the year ended June 30, 2011, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximate $20.4 million impact on our revenues.

Interest Rate Risk. As of August 24, 2011, we have no long-term debt subject to the risk of loss associated with movements in interest rates.

Item 8. *Financial Statements and Supplementary Data*

The financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented on pages F-1 through F-26 of this Form 10-K.

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

None.

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of the Company's senior management of the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")) as of June 30, 2011, the end of the period covered by this report. Based on that evaluation, the Company's management, including the Chairman and Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer, concluded that the Company's disclosure controls and procedures were effective as of such date to ensure that information required to be disclosed in the reports that the Company files under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) accumulated and communicated to the Company's management, including the Chairman, Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control Over Financial Reporting

There was no change in our internal controls over financial reporting during the three months ended June 30, 2011 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the Chairman, Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Company's evaluation under the framework in *Internal Control—Integrated Framework,* the Company's management concluded that its internal control over financial reporting was effective as of June 30, 2011.

Grant Thornton LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has audited the effectiveness of our internal control over financial reporting as of June 30, 2011, as stated in their report which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Contango Oil & Gas Company

We have audited Contango Oil & Gas Company (a Delaware corporation) and subsidiaries' internal control over financial reporting as of June 30, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Contango Oil & Gas Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on Contango Oil & Gas Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Contango Oil & Gas Company and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of June 30, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Contango Oil & Gas Company and subsidiaries as of June 30, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended June 30, 2011 and our report dated August 29, 2011 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Houston, Texas
August 29, 2011

Item 9B. ***Other Information***

On September 30, 2008, the Company adopted a Stockholder Rights Plan (the "Plan") that is designed to ensure that all stockholders of Contango receive fair value for their shares of common stock in the event of any proposed takeover of Contango and to guard against the use of partial tender offers or other coercive tactics to gain control of Contango without offering fair value to all of Contango's stockholders. The Plan is not intended, nor will it operate, to prevent an acquisition of Contango on terms that are favorable and fair to all stockholders.

Under the terms of the Plan, each right (a "Right") will entitle the holder to buy 1/100 of a share of Series F Junior Preferred Stock of Contango (the "Preferred Stock") at an exercise price of $200 per share. The Rights will be exercisable and will trade separately from the shares of common stock only if a person or group acquires beneficial ownership of 20% or more of Contango's common stock or commences a tender or exchange offer that would result in such a person or group owning 20% or more of the common stock (the "Triggering Event").

Under the terms of the Plan, Rights have been distributed as a dividend at the rate of one Right for each share of common stock held as of the close of business on October 1, 2008. Stockholders will not actually receive certificates for the Rights at this time, but the Rights will become part of each outstanding share of common stock. An additional Right will be issued along with each share of common stock that is issued or sold by Contango after October 1, 2008. The Rights may only be exercised during a three-year period and are scheduled to expire on September 30, 2011. Upon a Triggering Event, Contango stockholders will receive certificates for the Rights. Upon its expiration, the Company does not intend to renew the Plan.

If any person actually acquires 20% or more of shares of common stock — other than through a tender or exchange offer for all shares of common stock that provides a fair price and other acceptable terms for such shares, as determined by the board of directors of Contango — or if a 20%-or-more stockholder engages in certain "self-dealing" transactions or engages in a merger or other business combination in which Contango survives and its shares of common stock remain outstanding, the other Contango stockholders will be able to exercise the Rights and buy shares of common stock of Contango having approximately twice the value of the exercise price of the Rights. Additionally, if Contango is involved in certain other mergers where its shares are exchanged or certain major sales of its assets occur, Contango stockholders will be able to purchase a certain number of the other party's common stock in an amount equal to approximately twice the value of the exercise price of the Rights.

Contango will be entitled to redeem the Rights at $0.01 per Right at any time until the earlier of (i) the tenth day following public announcement that a person has acquired a 20% ownership position in shares of common stock of Contango or (ii) the final expiration date of the Rights. Contango in its discretion may extend the period during which it may redeem the Rights.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information regarding directors, executive officers, promoters and control persons required under Item 10 of Form 10-K will be contained in our Definitive Proxy Statement for our 2011 Annual Meeting of Stockholders (the "Proxy Statement") under the headings "Election of Directors", "Executive Compensation", "Section 16(a) Beneficial Ownership Reporting Compliance" and "Corporate Governance" and is incorporated herein by reference. The Proxy Statement will be filed with the SEC pursuant to Regulation 14A of the Exchange Act, not later than 120 days after June 30, 2011.

Item 11. ***Executive Compensation***

The information required under Item 11 of Form 10-K will be contained in the Proxy Statement under the heading "Executive Compensation" and is incorporated herein by reference.

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

The information required under Item 12 of Form 10-K will be contained in the Proxy Statement under the heading "Security Ownership of Certain Other Beneficial Owners and Management" and is incorporated herein by reference.

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

The information required under Item 13 of Form 10-K will be contained in the Proxy Statement under the heading "Certain Relationships and Related Transactions, and Director Independence" and "Executive Compensation" and is incorporated herein by reference.

Item 14. ***Principal Accountant Fees and Services***

The information required under Item 14 of Form 10-K will be contained in the Proxy Statement under the heading "Principal Accountant Fees and Services" and is incorporated herein by reference.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) Financial Statements and Schedules:

The financial statements are set forth in pages F-1 to F-21 of this Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibits:

The following is a list of exhibits filed as part of this Form 10-K. Where so indicated by a footnote, exhibits, which were previously filed, are incorporated herein by reference.

Exhibit Number	Description
2.1	Purchase and Sale Agreement, by and between Juneau Exploration, L.P. and REX Offshore Corporation, dated as of September 1, 2005. (10)
2.2	Purchase and Sale Agreement, by and between Juneau Exploration, L.P. and COE Offshore, LLC dated as of September 1, 2005. (10)
3.1	Certificate of Incorporation of Contango Oil & Gas Company. (5)
3.2	Bylaws of Contango Oil & Gas Company. (5)
3.3	Agreement of Plan of Merger of Contango Oil & Gas Company, a Delaware corporation, and Contango Oil & Gas Company, a Nevada corporation. (5)
3.4	Amendment to the Certificate of Incorporation of Contango Oil & Gas Company. (8)
4.1	Facsimile of common stock certificate of Contango Oil & Gas Company. (1)
4.4	Certificate of Designation of Series F Junior Preferred Stock of Contango Oil & Gas Company dated September 30, 2008. (16)
4.5	Rights Agreement, dated as of September 30, 2008, between Contango Oil & Gas Company and Computershare Trust Company, N.A., as Rights Agent. (16)
10.1	Agreement, dated effective as of September 1, 1999, between Contango Oil & Gas Company and Juneau

Exhibit Number	Description
	Exploration, L.L.C. (2)
10.2	Securities Purchase Agreement dated August 24, 2000 by and between Contango Oil & Gas Company and Trust Company of the West. (3)
10.3	Securities Purchase Agreement dated August 24, 2000 by and between Contango Oil & Gas Company and Fairfield Industries Incorporated. (3)
10.4	Securities Purchase Agreement dated August 24, 2000 by and between Contango Oil & Gas Company and Juneau Exploration Company, L.L.C. (3)
10.5	Amendment dated August 14, 2000 to agreement between Contango Oil & Gas Company and Juneau Exploration Company, LLC. dated effective as of September 1, 1999. (4)
10.6	Asset Purchase Agreement by and among Juneau Exploration, L.P. and Contango Oil & Gas Company dated January 4, 2002. (6)
10.7	Asset Purchase Agreement by and among Mark A. Stephens, John Miller, The Hunter Revocable Trust, Linda G. Ferszt, Scott Archer and the Archer Revocable Trust and Contango Oil & Gas Company dated January 9, 2002. (7)
10.8	Second Amended and Restated Credit Agreement dated as of October 1, 2010 among Contango Oil & Gas Company, Contango Operators, Inc. and Amegy Bank National Association, as Administrative Agent and Letter of Credit Issuer, together with First Amendment to Second Amended and Restated Credit Agreement dated October 20, 2010 among Contango Oil & Gas Company, Contango Operators, Inc. and Amegy Bank National Association. (19)
10.9	Purchase and Sale Agreement between Juneau Exploration, L.P. and Contango Operators, Inc. dated October 1, 2010. (20)
10.10	Purchase and Sale Agreement between Conterra Company as Seller, and Patara Oil & Gas LLC as Purchaser, dated April 22, 2011. (21)
10.11	Limited Liability Company Agreement of Republic Exploration LLC dated August 24, 2000. (10)
10.12	Amendment to Limited Liability Company Agreement and Additional Agreements of Republic Exploration LLC dated as of September 1, 2005. (10)
10.13	Limited Liability Company Agreement of Contango Offshore Exploration LLC dated November 1, 2000. (10)
10.14	First Amendment to Limited Liability Company Agreement and Additional Agreements of Contango Offshore Exploration LLC dated as of September 1, 2005. (10)
10.15*	Contango Oil & Gas Company 1999 Stock Incentive Plan. (11)
10.16*	Amendment No. 1 to Contango Oil & Gas Company 1999 Stock Incentive Plan dated as of March 1, 2001. (11)
10.17	Demand Promissory Note dated October 26, 2006 with Schedules I, II and III. (12)
10.18	Assignment of Operating Rights Interest between CGM, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.19	Partial Assignment of Oil and Gas Leases between CGM, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.20	Assignment of Operating Rights Interest between CGM, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.21	Assignment of Operating Rights Interest between Olympic Energy Partners, LLC and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.22	Partial Assignment of Oil and Gas Leases between Olympic Energy Partners, LLC and Contango Operators, Inc. dated as of January 3, 2008. (13)
10.23	Assignment of Operating Rights Interest between Olympic Energy Partners, LLC and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.24	Assignment of Operating Rights Interest between Juneau Exploration, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.25	Partial Assignment of Oil and Gas Leases between Juneau Exploration, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.26	Assignment of Operating Rights Interest between Juneau Exploration, LP and Contango Operators, Inc., dated as of January 3, 2008. (13)
10.27	Assignment of Operating Rights Interest between Juneau Exploration, LP and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.28	Partial Assignment of Oil and Gas Leases between Juneau Exploration, LP and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.29	Assignment of Operating Rights Interest between Juneau Exploration, LP and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.30	Assignment of Operating Rights Interest between Olympic Energy Partners, LLC and Contango Operators, Inc.,

Exhibit Number	Description
	dated as of April 3, 2008. (14)
10.31	Partial Assignment of Oil and Gas Leases between Olympic Energy Partners, LLC and Contango Operators, Inc. dated as of April 3, 2008. (14)
10.32	Assignment of Operating Rights Interest between Olympic Energy Partners, LLC and Contango Operators, Inc., dated as of April 3, 2008. (14)
10.33	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.34	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.35	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.36	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.37	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.38	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.39	Assignment of Overriding Royalty Interest between Dutch Royalty Investments, Land and Leasing, LP and Contango Operators, Inc., dated as of February 8, 2008. (15)
10.40	Amended and Restated Limited Liability Company Agreement of Republic Exploration LLC, dated April 1, 2008. (14)
10.41	Amended and Restated Limited Liability Company Agreement of Contango Offshore Exploration LLC, dated April 1, 2008. (15)
10.42	$50,000,000 Amended and Restated Credit Agreement dated as of March 31, 2009 among Contango Oil & Gas Company, Contango Energy Company and Contango Operators Inc. as Borrowers, Guaranty Bank, as administrative agent and issuing lender, and the lenders party thereto from time to time. (17)
10.43*	Contango Oil & Gas Company Annual Incentive Plan. (22)
10.44*	Contango Oil & Gas Company 2009 Equity Compensation Plan. (22)
10.45	Conterra Joint Venture Development Agreement effective October 1, 2009 between Conterra Company and Patara Oil & Gas LLC. (18)
14.1	Code of Ethics. (11)
21.1	List of Subsidiaries. †
21.2	Organizational Chart. †
23.1	Consent of William M. Cobb & Associates, Inc. †
23.2	Consent of Lonquist & Co. LLC
23.3	Consent of Grant Thornton LLP. †
31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934. †
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. †
99.1	Report of William M. Cobb & Associates, Inc. †

† Filed herewith.

* Indicates a management contract or compensatory plan or arrangement.

* Indicates a management contract or compensatory plan or arrangement.

1. Filed as an exhibit to the Company's Form 10-SB Registration Statement, as filed with the Securities and Exchange Commission on October 16, 1998.
2. Filed as an exhibit to the Company's report on Form 10-QSB for the quarter ended September 30, 1999, as filed with the Securities and Exchange Commission on November 11, 1999.
3. Filed as an exhibit to the Company's report on Form 8-K, dated August 24, 2000, as filed with the Securities and Exchange Commission of September 8, 2000.
4. Filed as an exhibit to the Company's annual report on Form 10-KSB for the fiscal year ended June 30, 2000, as filed with the Securities and Exchange Commission on September 27, 2000.

5. Filed as an exhibit to the Company's report on Form 8-K, dated December 1, 2000, as filed with the Securities and Exchange Commission on December 15, 2000.
6. Filed as an exhibit to the Company's report on Form 8-K, dated January 4, 2002, as filed with the Securities and Exchange Commission on January 8, 2002.
7. Filed as an exhibit to the Company's report on Form 10-QSB for the quarter ended March 31, 2002, as filed with the Securities and Exchange Commission on February 14, 2002.
8. Filed as an exhibit to the Company's report on Form 10-QSB for the quarter ended December 31, 2002, dated November 14, 2002, as filed with the Securities and Exchange Commission.
9. Filed as an exhibit to the Company's annual report on Form 10-KSB for the fiscal year ended June 30, 2003, as filed with the Securities and Exchange Commission on September 22, 2003.
10. Filed as an exhibit to the Company's report on Form 8-K, dated September 2, 2005, as filed with the Securities and Exchange Commission on September 8, 2005.
11. Filed as an exhibit to the Company's report on Form 10-K for the fiscal year ended June 30, 2005, as filed with the Securities and Exchange Commission on September 13, 2005.
12. Filed as an exhibit to the Company's report on Form 10-Q for the quarter ended September 30, 2006, dated November 8, 2006, as filed with the Securities and Exchange Commission.
13. Filed as an exhibit to the Company's report on Form 8-K, dated January 3, 2008, as filed with the Securities and Exchange Commission on January 9, 2008.
14. Filed as an exhibit to the Company's report on Form 8-K, dated April 3, 2008, as filed with the Securities and Exchange Commission on April 9, 2008.
15. Filed as an exhibit to the Company's report on Form 10-K for the fiscal year ended June 30, 2008, as filed with the Securities and Exchange Commission on August 29, 2008.
16. Filed as an exhibit to the Company's report on Form 8-K, dated September 30, 2008, as filed with the Securities and Exchange Commission on October 1, 2008.
17. Filed as an exhibit to the Company's report on Form 10-Q for the quarter ended March 31, 2009, as filed with the Securities and Exchange Commission on May 11, 2009.
18. Filed as an exhibit to the Company's report on Form 8-K, dated October 22, 2009, as filed with the Securities and Exchange Commission on October 28, 2009.
19. Filed as an exhibit to the Company's report on Form 8-K, dated October 20, 2010 as filed with the Securities and Exchange Commission on October 25, 2010.
20. Filed as an exhibit to the Company's report on Form 10-Q for the quarter ended September 30, 2010, as filed with the Securities and Exchange Commission on November 9, 2010.
21. Filed as an exhibit to the Company's report on Form 8-K, dated May 13, 2011 as filed with the Securities and Exchange Commission on May 18, 2011.
22. Filed as an exhibit to the Company's report on Form 10-K for the fiscal year ended June 30, 2010, as filed with the Securities and Exchange Commission on September 13, 2010.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONTANGO OIL & GAS COMPANY

/s/ KENNETH R. PEAK	/s/ SERGIO CASTRO	/s/ YAROSLAVA MAKALSKAYA
Kenneth R. Peak	Sergio Castro	Yaroslava Makalskaya
Chief Executive Officer	Chief Financial Officer	Vice President and Controller
(principal executive officer)	(principal financial officer)	(principal accounting officer)

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ KENNETH R. PEAK Kenneth R. Peak	Chairman of the Board	August 29, 2011
/s/ B.A. BERILGEN B.A. Berilgen	Director	August 29, 2011
/s/ JAY D. BREHMER Jay D. Brehmer	Director	August 29, 2011
/s/ CHARLES M. REIMER Charles M. Reimer	Director	August 29, 2011
/s/ STEVEN L. SCHOONOVER Steven L. Schoonover	Director	August 29, 2011

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Contango Oil & Gas Company

We have audited the accompanying consolidated balance sheets of Contango Oil & Gas Company (a Delaware corporation) and subsidiaries as of June 30, 2011 and 2010, and the related consolidated statements of operations, shareholders' equity and 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Contango Oil & Gas Company and subsidiaries as of June 30, 2011 and 2010, and the results of their operations and their 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Contango Oil & Gas Company and subsidiaries' internal control over financial reporting as of June 30, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated August 29, 2011 expressed an unqualified opinion on the internal control over financial reporting.

/s/ GRANT THORNTON LLP
Houston, Texas
August 29, 2011

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

ASSETS

	June 30, 2011	June 30, 2010
CURRENT ASSETS:		
Cash and cash equivalents	$ 150,007	$ 52,469
Accounts receivable:		
Trade receivable	43,967	41,938
Joint interest billings	6,818	11,759
Income taxes	94	5,410
Other receivables	978	3,165
Notes receivables	-	2,028
Other	3,014	3,104
Total current assets	204,878	119,873
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	552,556	540,216
Unproved properties	7,625	10,825
Furniture and equipment	227	277
Accumulated depreciation, depletion and amortization	(129,702)	(78,998)
Total property, plant and equipment, net	430,706	472,320
OTHER ASSETS:		
Other	1,346	73
TOTAL ASSETS	$ 636,930	$ 592,266

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

LIABILITIES AND SHAREHOLDERS' EQUITY

	June 30, 2011		June 30, 2010	
CURRENT LIABILITIES:				
Accounts payable	$	11,857	$	34,220
Royalties and revenue payable		39,222		30,774
Accrued liabilities		9,745		2,647
Joint interest advances		3,995		740
Accrued exploration and development		6,002		9,263
Income tax payable		6,942		844
Other current liabilities		461		-
Total current liabilities		78,224		78,488
DEFERRED TAX LIABILITY		123,472		131,291
ASSET RETIREMENT OBLIGATION		8,611		5,157
COMMITMENTS AND CONTINGENCIES (NOTE 12)				
SHAREHOLDERS' EQUITY:				
Common stock, $0.04 par value, 50 million shares authorized, 20.1 million shares issued and 15.7 million outstanding at June 30, 2011, 20.0 million shares issued and 15.7 million outstanding at June 30, 2010,		805		799
Additional paid-in capital		79,278		77,968
Treasury stock at cost (4.4 million and 4.3 million shares, respectively)		(91,788)		(82,019)
Retained earnings		438,328		380,582
Total shareholders' equity		426,623		377,330
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$	636,930	$	592,266

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended June 30,		
	2011	**2010**	**2009**
REVENUES:			
Natural gas and oil sales	$ 203,778	$ 159,010	$ 190,656
Total revenues	203,778	159,010	190,656
EXPENSES:			
Operating expenses	25,989	16,692	23,684
Exploration expenses	9,751	20,850	20,603
Depreciation, depletion and amortization	55,231	34,521	32,673
Impairment of natural gas and oil properties	1,786	952	11,075
General and administrative expense	12,341	4,599	9,467
Total expenses	105,098	77,614	97,502
OTHER INCOME (EXPENSE)	(158)	398	184
GAIN (LOSS) ON SALE OF ASSETS	(273)	113	(530)
NET INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	98,249	81,907	92,808
Provision for income taxes	(34,797)	(31,741)	(36,947)
INCOME FROM CONTINUING OPERATIONS	63,452	50,166	55,861
DISCONTINUED OPERATIONS (Note 6)			
Discontinued operations, net of income taxes	1,581	(480)	-
NET INCOME ATTRIBUTABLE TO COMMON STOCK	$ 65,033	$ 49,686	$ 55,861
NET INCOME PER SHARE:			
Basic			
Continuing operations	$ 4.05	$ 3.17	$ 3.41
Discontinued operations	0.10	(0.03)	-
Total	$ 4.15	$ 3.14	$ 3.41
Diluted			
Continuing operations	$ 4.04	$ 3.11	$ 3.35
Discontinued operations	0.10	(0.03)	-
Total	$ 4.14	$ 3.08	$ 3.35
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	15,665	15,831	16,363
Diluted	15,713	16,157	16,690

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended June 30,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income from continuing operations	$ 63,452	$ 50,166	$ 55,861
Plus income (loss) from discontinued operations, net of income taxes	1,581	(480)	-
Net income	65,033	49,686	55,861
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	59,337	35,374	32,673
Impairment of natural gas and oil properties	2,315	952	11,075
Exploration expenses	9,657	20,502	19,039
Deferred income taxes	(7,819)	19,399	(1,226)
Gain on sale of assets	(1,813)	(113)	-
Stock-based compensation	1,276	667	1,382
Tax benefit from exercise of stock options	(502)	(79)	(264)
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable and other	(2,029)	(9,129)	39,689
Decrease (increase) in prepaids and other receivables	1,671	(3,234)	(19)
Increase (decrease) in accounts payable and advances from joint owners	(5,718)	14,846	(11,598)
Increase (decrease) in other accrued liabilities	7,142	301	(43,819)
Increase (decrease) in income taxes receivable, net	11,917	662	(7,421)
Other	91	(1,646)	-
Net cash provided by operating activities	140,558	128,188	95,372
CASH FLOWS FROM INVESTING ACTIVITIES:			
Natural gas and oil exploration and development expenditures	(69,904)	(97,699)	(45,742)
Additions to furniture and equipment	(89)	(4)	(16)
Repayment of note receivable	2,028	-	-
Investments in affiliates	(3,959)	-	-
Proceeds from the sale of assets	38,671	-	-
Net cash used in investing activities	(33,253)	(97,703)	(45,758)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayments under credit facility	-	-	(15,000)
Dividends	(6)	-	-
Purchase of common stock	(9,769)	(23,380)	(51,795)
Proceeds from exercised options	-	914	1,654
Tax benefit from exercise/cancellation of stock options	502	79	264
Debt issuance costs	(494)	-	(251)
Net cash used in financing activities	(9,767)	(22,387)	(65,128)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	97,538	8,098	(15,514)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	52,469	44,371	59,885
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 150,007	$ 52,469	$ 44,371
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid for taxes, net of cash received	$ 31,876	$ 11,535	$ 45,592
Cash paid for interest	$ 60	$ 250	$ 398

	Year Ended June 30,		
	2011	2010	2009
SUPPLEMENTAL NON-CASH ACTIVITY:			
Increase in non-recourse demand promissory note	$ -	$ 2,028	$ -

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
(in thousands)

	Common Stock	Additional Paid-in Capital				
	Shares		**Treasury Stock**	**Retained Earnings**	**Total Shareholders' Equity**	**Amount**
Balance at June 30, 2008	16,820	$ 776	$ 73,031	$ (6,844)	$ 275,035	$ 341,998
Exercise of stock options	231	9	1,645	-	-	1,654
Tax benefit from exercise of stock options	-	-	264	-	-	264
Amortization of restricted stock	3	-	241	-	-	241
Treasury shares at cost	(1,224)	-	-	(51,795)	-	(51,795)
Stock option expense	-	-	1,141	-	-	1,141
Net income	-	-	-	-	55,861	55,861
Balance at June 30, 2009	15,830	$ 785	$ 76,322	$ (58,639)	$ 330,896	$ 349,364
Exercise of stock options	344	14	900	-	-	914
Tax benefit from exercise of stock options	-	-	79	-	-	79
Amortization of restricted stock	-	-	72	-	-	72
Treasury shares at cost	(489)	-	-	(23,380)	-	(23,380)
Stock option expense	-	-	595	-	-	595
Net income	-	-	-	-	49,686	49,686
Balance at June 30, 2010	15,685	$ 799	$ 77,968	$ (82,019)	$ 380,582	$ 377,330
Exercise of stock options	153	6	(6)	-	-	-
Tax benefit from exercise of stock options	-	-	502	-	-	502
Treasury shares at cost	(173)	-	-	(9,769)	-	(9,769)
Stock option expense	-	-	814	-	-	814
Dividends	-	-	-	-	(7,287)	(7,287)
Net income	-	-	-	-	65,033	65,033
Balance at June 30, 2011	15,665	$ 805	$ 79,278	$ (91,788)	$ 438,328	$ 426,623

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Business

Contango Oil & Gas Company (collectively with its subsidiaries, "Contango" or the "Company") is a Houston-based, independent natural gas and oil company. The Company's business is to explore, develop, produce and acquire natural gas and oil properties primarily offshore in the Gulf of Mexico in water-depths of less than 300 feet.

2. Summary of Significant Accounting Policies

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. The most significant estimates include income taxes, stock-based compensation, reserve estimates and impairment of natural gas and oil properties. Actual results could differ from those estimates.

Revenue Recognition. Revenues from the sale of natural gas and oil produced are recognized upon the passage of title, net of royalties. Revenues from natural gas production are recorded using the sales method. When sales volumes exceed the Company's entitled share, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. At June 30, 2011 and 2010, the Company had no significant imbalances.

Cash Equivalents. Cash equivalents are considered to be highly liquid investment grade debt investments having an original maturity of 90 days or less. As of June 30, 2011, the Company had approximately $150 million in cash and cash equivalents. Of this amount, approximately $11.7 million was invested in U.S. Treasury money market funds, $22.3 million was invested in overnight U.S. Treasury funds, and the remaining $116 million was in non-interest bearing accounts.

Accounts Receivable. The Company sells natural gas and crude oil to a limited number of customers. In addition, the Company participates with other parties in the operation of natural gas and crude oil wells. Substantially all of the Company's accounts receivables are due from either purchasers of natural gas and crude oil or participants in natural gas and crude oil wells for which the Company serves as the operator. Generally, operators of natural gas and crude oil properties have the right to offset future revenues against unpaid charges related to operated wells.

The allowance for doubtful accounts is an estimate of the losses in the Company's accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Amounts deemed uncollectible are charged to the allowance.

Accounts receivable allowance for bad debt was $0 at June 30, 2011 and 2010. At June 30, 2011 and 2010, the carrying value of the Company's accounts receivable approximated fair value.

Net Income per Common Share. Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. See Note 8 – Net Income Per Common Share for the calculations of basic and diluted net income per common share.

Income Taxes. The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (ii) operating loss and tax credit carryforwards for tax purposes. Deferred tax assets are reduced by a valuation allowance when, based upon management's estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in a future period. The Company reviews its tax positions quarterly for tax uncertainties. The Company did not have significant uncertain tax positions as of June 30, 2011. The amount of unrecognized tax benefits did not materially change from June 30, 2010. The amount of unrecognized tax benefits may change in the next twelve months; however, we do not expect the change to have a significant impact on our financial position or results of operations. The Company includes interest and penalties in interest income and general and administrative expenses, respectively, in its statement of operations.

The Company files income tax returns in the United States and various state jurisdictions. The Company's tax returns for 2007 – 2010 remain open for examination by the taxing authorities in the respective jurisdictions where those returns were filed.

Concentration of Credit Risk. Substantially all of the Company's accounts receivable result from natural gas and oil sales or joint interest billings to a limited number of third parties in the natural gas and oil industry. This concentration of customers and joint interest owners may impact the Company's overall credit risk in that these entities may be similarly affected by changes in economic and other conditions.

Consolidated Statements of Cash Flows. Significant transactions, such as issuing restricted stock or stock options, may occur that do not directly affect cash balances and, as such, are not disclosed in the Consolidated Statements of Cash Flows. Certain such non-cash transactions are disclosed in the Statements of Shareholders' Equity and footnotes to the Consolidated Financial Statements.

Fair Value of Financial Instruments. The carrying amounts of the Company's short-term financial instruments, including cash equivalents, short-term investments, trade accounts receivable and accounts payable, approximate their fair values based on the short maturities of those instruments.

Successful Efforts Method of Accounting. The Company follows the successful efforts method of accounting for its natural gas and oil activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs, such as seismic costs and other geological and geophysical expenses, are expensed as incurred. Depreciation, depletion and amortization is calculated on a field by field basis using the unit of production method, with lease acquisition costs amortized over total proved reserves and other capitalized costs amortized over proved developed reserves.

Impairment of Long-Lived Assets. When circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted cash flows, based on the Company's estimate of future reserves, natural gas and oil prices and operating costs and anticipated production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to its fair value. For the fiscal year ended June 30, 2009, the Company's analysis determined that Grand Isle 70 and Grand Isle 72 were impaired. The Company recorded an impairment charge of approximately $2.5 million and $3.4 million, respectively, related to these fields. The Company did not recognize impairment of proved properties for the fiscal years ended June 30, 2011 or 2010.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, and any such impairment is charged to expense in the period. For the year ended June 30, 2011, the Company recorded impairment expense of approximately $1.8 million related to the relinquishment of 14 unproven lease blocks owned by Contango and Republic Exploration LLC ("REX"). For the year ended June 30, 2010, the Company recorded impairment expense of approximately $1.0 million, related to the relinquishment of six unproven lease blocks owned by REX and Contango Offshore Exploration ("COE"). For the fiscal year ended June 30, 2009, the Company recorded $5.2 million in impairment charges related to the expiration and relinquishment of 44 unproven lease blocks owned by REX and COE.

Discontinued Operations. An integral and on-going part of our business strategy is to sell our proved reserves from time to time in order to generate additional capital to reinvest in our onshore and offshore exploration programs. When applicable, the disposition of these assets is classified as discontinued operations for all periods presented.

Principles of Consolidation. The Company's consolidated financial statements include the accounts of Contango Oil & Gas Company and its subsidiaries, after elimination of all material intercompany balances and transactions. Wholly-owned subsidiaries are fully consolidated. Exploration and development affiliates not wholly owned, such as REX, are not controlled by the Company and are proportionately consolidated.

For the period ending June 30, 2009, the company also proportionately consolidated the results of COE. Effective June 1, 2010 COE was dissolved, and all assets and liabilities owned by COE were distributed to its members.

Other Investments. Contango's 19.5% ownership of Moblize Inc. ("Moblize") and 2.0% ownership of Alta Energy Partners LLC ("Alta Energy") is accounted for using the cost method. Under the cost method, Contango records an investment in the stock of an investee at cost, and recognizes dividends received as income. Dividends received in excess of earnings subsequent to the date of investment are considered a return of investment and are recorded as reductions of cost of the investment. In fiscal year 2010, the Company recognized a $190,000 impairment of its investment in Moblize.

Reclassifications. Certain reclassifications have been made to the fiscal year 2010 and 2009 amounts in order to conform to the 2011 presentation. These reclassifications were not material.

Stock-Based Compensation. The Company applies the fair value based method to account for stock based compensation. Under this method, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the award vesting period. The Company classifies the benefits of tax deductions in excess of the compensation cost recognized for the options (excess tax benefit) as financing cash flows. The fair value of each award is estimated as of the date of grant using the Black-Scholes option-pricing model.

Liability Accounting for Stock Options. In November 2010, the Company's Board of Directors approved the immediate vesting of all outstanding stock options and authorized management to net-settle any outstanding stock options in cash. As a result, the Company reclassified all outstanding stock options from equity instruments to liability instruments. This resulted in recognizing a liability equal to the portion of each award attributable to past service multiplied by the modified award's fair value. The liability for the outstanding stock options is based on the fair value of each award evaluated at the end of each quarter using the Black-Scholes option-pricing model. To the extent that the liability exceeds the amount recognized at the end of the previous period, the difference is recognized as compensation cost in the statement of operations for each period until the stock options are settled.

Derivative Instruments and Hedging Activities. The Company did not enter into any derivative instruments or hedging activities for the fiscal years ended June 30, 2011, 2010 or 2009, nor did we have any open commodity derivative contracts at June 30, 2011.

Asset Retirement Obligation. The Company accounts for its retirement obligation of long lived assets by recording the net present value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. When the liability is initially recorded, a company increases the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. Activities related to the Company's ARO during the year ended June 30, 2011 and 2010 were as follows:

	Year Ended June 30,	
(thousands)	**2011**	**2010**
Balance as of July 1	$ 5,157	$ 3,470
Liabilities incurred during period	1,613	1,665
Liabilities settled during period	(157)	(400)
Accretion	386	177
Change in estimate	1,612	245
Balance as of June 30	$ 8,611	$ 5,157

Recent Accounting Pronouncements. In June 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-05: *Comprehensive Income (Topic 220): Presentation of Comprehensive Income* (ASU 2011-05). ASU 2011-05 provides that an entity that reports items of other comprehensive income has the option to present comprehensive income in either one continuous financial statement or two consecutive financial statements. ASU 2011-05 is effective for annual periods beginning after December 15, 2011. We do not anticipate the implementation to have any effect on the Company's financial position or results of operations.

In May 2011, the FASB issued Accounting Standards Update No. 2011-04: *Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04). ASU 2011-04 clarifies application of fair value measurement and disclosure requirements and is effective for annual periods beginning after December 15, 2011. We are currently evaluating the provisions of ASU 2011-04 and assessing the impact, if any, it may have on our financial position and results of operations.

On January 1, 2011, we implemented certain provisions of Accounting Standards Update No. 2010-06: *Fair Value Measurements and Disclosures (Topic 820) – Improving Disclosures about Fair Value Measurements* (ASU 2010-06). ASU 2010-06 requires entities to provide a reconciliation of purchases, sales, issuance and settlements of anything valued with a Level 3 method, which is used to price the hardest to value instruments. The implementation did not have an impact on our consolidated results of operations, financial position or cash flows.

3. Natural Gas and Oil Exploration and Production Risk

The Company's future financial condition and results of operations will depend upon prices received for its natural gas and oil production and the cost of finding, acquiring, developing and producing reserves. Substantially all of its production is sold under various terms and arrangements at prevailing market prices. Prices for natural gas and oil are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond the Company's control.

Other factors that have a direct bearing on the Company's financial condition are uncertainties inherent in estimating natural gas and oil reserves and future hydrocarbon production and cash flows, particularly with respect to wells that have not been fully tested and with wells having limited production histories; the timing and costs of our future drilling; development and abandonment activities; access to additional capital; changes in the price of natural gas and oil; availability and cost of services and equipment; and the presence of competitors with greater financial resources and capacity.

4. Concentration of Credit Risk

The customer base for the Company is concentrated in the natural gas and oil industry. Major purchasers of our natural gas, oil and natural gas liquids for the fiscal year ended June 30, 2011 were Shell Trading US Company (26%), NJR Energy Services (25%), ConocoPhillips Company (23%), Enterprise Products Operating LLC (9%), and TransLouisiana Gas Pipeline, Inc. (7%). Our sales to these companies are not secured with letters of credit and in the event of non-payment, we could lose up to two months of revenues. The loss of two months of revenues would have a material adverse effect on our financial position. There are numerous other potential purchasers of our production.

5. Other Receivables

On February 24, 2010, a dredge contracted by the Army Corps of Engineers to dredge the Atchafalaya River Channel ruptured the Company's 20" pipeline that runs from our Eugene Island 11 gathering platform to our Eugene Island 63 auxiliary platform where our pipeline joins a third-party pipeline that transports our production to shore. The pipeline was repaired and production resumed on March 31, 2010. Of the receivable of approximately $3.2 million in the Balance Sheet as of June 30, 2010, $2.9 million related to this incident. We received the entire $2.9 million from the insurance company during the year ended June 30, 2011.

6. Discontinued Operations

On May 13, 2011 the Company sold substantially all of its onshore Texas assets to Patara Oil & Gas LLC ("Patara") for an aggregate purchase price of $40 million ($38.7 million after adjustments). The properties were sold effective April 1, 2011 and include: (i) the Company's 90% interest and 5% overriding royalty interest in the 21 wells drilled under a joint venture with Patara (the "Joint Venture Assets"); (ii) the Company's 100% working interest (72.5% net revenue interest) in Rexer #1 drilled in south Texas; and (iii) a 75% working interest (54.4% net revenue interest) in Rexer #2, which was spud on May 11, 2011. The Company has accounted for the sale of the Joint Venture Assets as discontinued operations as of June 30, 2011 and reclassified the results of its operations and the loss on disposition to discontinued operations for all periods presented.

Joint Venture Assets

The Company entered into a joint venture with Patara in October 2009 to develop proved undeveloped Cotton Valley gas reserves in Panola County, Texas. B.A. Berilgen, a member of the Company's board of directors, is the Chief Executive Officer of Patara. The Company sold these assets for approximately $36.2 million and recognized a pre-tax loss on sale of approximately $0.7 million. These 21 wells had proved reserves of approximately 16.7 Bcfe, net to Contango. The summarized financial results for the Joint Venture Assets for the periods ended June 30, 2011 and 2010 are as follows:

Results of Operations:

	June 30,	
(thousands)	**2011**	**2010**
Revenues	$ 8,055	$ 1,671
Operating expenses	(1,613)	(327)
Depletion expenses	(4,106)	(874)
Exploration expenses	(527)	(2)
	1,809	468
Loss on sale	(651)	-

(thousands)	June 30, 2011	June 30, 2010
Income before income taxes	$ 1,158	$ 468
Provision for income taxes	(617)	(164)
Gain from discontinued operations, net of income taxes	$ 541	$ 304

Additionally, the Company distributed the common stock of Contango ORE, Inc. ("CORE") to the Company's shareholders. CORE was a wholly-owned subsidiary of the Company formed to explore for gold and rare earth elements in Alaska.

Contango Mining Company

On September 29, 2010, Contango ORE, Inc. ("CORE"), then a wholly-owned subsidiary of the Company, filed with the Securities and Exchange Commission a Registration Statement on Form 10 which became effective November 29, 2010. Following the effective date, CORE acquired the assets and assumed the liabilities of Contango Mining Company ("Contango Mining"), another wholly-owned subsidiary of the Company. Additionally, subsequent to the effective date, the Company contributed $3.5 million of cash to CORE. In exchange, CORE issued 1,566,367 shares of its common stock to the Company in addition to the 100 shares which the Company held prior to that date. The Company distributed all its shares of CORE, valued at approximately $7.3 million, to its stockholders of record as of October 15, 2010 on the basis of one share of common stock of CORE for each ten shares of the Company's common stock then outstanding. In addition to the distribution of shares of CORE, the Company paid $6,213 in cash to its stockholders of record in exchange for partial shares.

As of June 30, 2011, the assets and liabilities of Contango Mining were excluded from the Company's financial statements. The assets and liabilities of the Contango Mining included in the Company's Balance Sheet as of June 30, 2010 were as follows:

(thousands)	June 30, 2010
Cash	$ -
Other current assets	233
Mineral properties	1,009
Current liabilities	(511)

Results of operations of Contango Mining for the fiscal year ended June 30, 2011 and for each of the previous periods are included in discontinued operations in the Company's Statement of Operations. The summarized financial results for Contango Mining for the fiscal years ended June 30, 2011 and 2010 were as follows:

Operating Results:

(thousands)	June 30, 2011	June 30, 2010
Revenues	$ -	$ -
Exploration expenses	(983)	(1,102)
General and administrative expenses	(154)	-
Gain on sale of discontinued operations	2,737	-
Gain before income taxes	$ 1,600	$ (1,102)
Provision for income taxes	(560)	318
Gain from discontinued operations, net of income taxes	$ 1,040	$ (784)

The Gain on sale of discontinued operations represents the difference between $7.3 million, the fair value of the shares of CORE distributed to the Company's shareholders, and the historical value of the assets and liabilities transferred to CORE on or subsequent to November 29, 2010.

7. Sale of Properties – Other

On May 13, 2011, in conjunction with the sale of our discontinued operations, the Company also sold 100% of its interest in Rexer #1 and 75% of its interest in Rexer-Tusa #2 to the same independent oil and gas company for approximately $2.5 million and recognized a pre-tax loss on sale of approximately $0.3 million. Rexer #1 is a wildcat exploration well that was spud in June 2010 and began producing in October 2010. This well had proved reserves of approximately 0.5 Bcfe, net to Contango. Rexer-Tusa #2 is another wildcat exploration well that was spud in May 2011. This well had no proved reserves at the time of sale. The Company retained a 25% working interest in the Rexer-Tusa #2 well and has included the results of operations and the loss on sale of the two wells in continuing operations.

8. Net Income Per Common Share

A reconciliation of the components of basic and diluted net income per common share for the fiscal years ended June 30, 2011, 2010 and 2009 is presented below:

	Year Ended June 30, 2011		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Income from continuing operations	$ 63,452	15,665	$ 4.05
Discontinued operations, net of income taxes	1,581	15,665	0.10
Basic Earnings per Share:			
Net income attributable to common stock	$ 65,033	15,665	$ 4.15
Effect of Potential Dilutive Securities:			
Stock options, net of shares assumed purchased	-	48	
Income from continuing operations	$ 63,452	15,713	$ 4.04
Discontinued operations, net of income taxes	1,581	15,713	0.10
Diluted Earnings per Share:			
Net income attributable to common stock	$ 65,033	15,713	$ 4.14

8. Net Income Per Common Share – continued

	Year Ended June 30, 2010		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Income from continuing operations	$ 50,166	15,831	$ 3.17
Discontinued operations, net of income taxes	(480)	15,831	(0.03)
Basic Earnings per Share:			
Net income attributable to common stock	$ 49,686	15,831	$ 3.14
Effect of Potential Dilutive Securities:			
Stock options, net of shares assumed purchased	-	326	
Income from continuing operations	$ 50,166	16,157	$ 3.11
Discontinued operations, net of income taxes	(480)	16,157	(0.03)
Diluted Earnings per Share:			
Net income attributable to common stock	$ 49,686	16,157	$ 3.08

	Year Ended June 30, 2009		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Income from continuing operations	$ 55,861	16,363	$ 3.41
Discontinued operations, net of income taxes	-	16,363	-
Basic Earnings per Share:			
Net income attributable to common stock	$ 55,861	16,363	$ 3.41
Effect of Potential Dilutive Securities:			
Stock options, net of shares assumed purchased	-	326	
Restricted shares	-	1	
Income from continuing operations	$ 55,861	16,690	$ 3.35

	Year Ended June 30, 2009		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Discontinued operations, net of income taxes	-	16,690	-
Diluted Earnings per Share:			
Net income attributable to common stock	$ 55,861	16,690	$ 3.35

Options to purchase 70,000 and 45,000 shares of common stock were outstanding as of June 30, 2010 and 2009, respectively, but were not included in the computation of diluted earnings per share for the fiscal year ended June 30, 2010 or 2009. These options were excluded because either (i) the options' exercise price was greater than the average market price of the common shares, or (ii) application of the treasury method to in-the-money options made some of the options anti-dilutive.

9. Change in Ownership of Partially-Owned Subsidiaries and Overriding Royalties

COE was dissolved on June 1, 2010. Prior to its dissolution, COE was 65.6% owned by Contango, and JEX would generate natural gas and oil prospects through COE. Immediately prior to its dissolution, COE owed the Company $5.9 million in principal and interest under a promissory note (the "COE Note") payable on demand. In connection with the dissolution, the Company assumed its 65.6% share of the obligation under the COE Note, while the other member of COE assumed the remaining 34.4%, or approximately $2 million. This $2 million was paid back to the Company during the fiscal year ended June 30, 2011.

10. Income Taxes

Actual income tax expense from continuing operations differs from income tax expense from continuing operations computed by applying the U.S. federal statutory corporate rate of 35 percent to pretax income as follows:

	Year Ended June 30,					
(thousands)	2011		2010		2009	
Provision at statutory tax rate	$ 34,387	35.0%	$ 28,445	35.00%	$ 32,484	35.0%
State income tax provision, net of federal benefit	2,985	3.04%	1,415	1.74%	4,120	4.44%
Permanent differences	(2,678)	-2.73%	(465)	-0.57%	343	0.37%
Other	103	0.10%	2,346	2.89%	-	- %
Income tax provision	$ 34,797	35.41%	$ 31,741	39.06%	$ 36,947	39.81%

The provision (benefit) for income taxes from continuing operations for the periods indicated are comprised of the following:

	Year Ended June 30,		
(thousands)	2011	2010	2009
Current:			
Federal	$ 34,294	$ 16,564	$ 31,225
State	3,502	598	6,948
Total	$ 37,796	$ 17,162	$ 38,173
Deferred:			
Federal	$ (1,984)	$ 13,503	$ (617)
State	(1,015)	1,076	(609)
Total	$ (2,999)	$ 14,579	$ (1,226)
Total:			
Federal	$ 32,310	$ 30,067	$ 30,608
State	2,487	1,674	6,339
Total	$ 34,797	$ 31,741	$ 36,947

The net deferred tax liability is comprised of the following:

(thousands)	Year Ended June 30, 2011	2010	2009
Deferred tax liability:			
Temporary basis differences in natural gas and oil properties and other	$ (123,472)	$ (131,291)	$ (110,964)
Net deferred tax liability	$ (123,472)	$ (131,291)	$ (110,964)

11. Long-Term Debt

On October 22, 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the "Credit Agreement") to replace the expiring credit agreement with BBVA Compass Bank. The Credit Agreement currently has a $40 million hydrocarbon borrowing base and will be available to fund the Company's offshore Gulf of Mexico exploration and development activities, as well as repurchase shares of common stock, pay dividends, and fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. The principal is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of $300,000 was paid in connection with the facility and a commitment fee of 0.375% will be paid on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of June 30, 2011, the Company was in compliance with all covenants and had no amounts outstanding under the Credit Agreement.

The Company's $50 million hydrocarbon borrowing base secured revolving credit facility with BBVA Compass expired in October 2010. The credit facility was secured by substantially all of the Company's assets. Borrowings under the Compass Agreement carried interest at LIBOR plus 2.0% per annum. An arrangement fee of 0.5%, or $250,000, was paid in connection with the facility and a commitment fee of 0.5% was paid on the unused commitment amount.

12. Commitments and Contingencies

Contango pays delay rentals on its offshore leases and leases its office space and certain other equipment. In November 2010, the Company expanded its office space and extended its office lease agreement through December 31, 2015. As of June 30, 2011, minimum future lease payments for our fiscal years are as follows:

Fiscal years ending June 30,

(thousands)	
2012	$ 409
2013	404
2014	359
2015	354
2016 and thereafter	126
Total	$ 1,652

The amount incurred under operating leases and delay rentals during the years ended June 30, 2011, 2010 and 2009 was approximately $288,000, $692,000, and $1.3 million, respectively. Additionally, the Company pays a commitment fee of 0.375% on the unused borrowing capacity of our $40 million credit facility with Amegy Bank (See Note 11—"Long Term Debt"), and we have committed to invest up to $20 million over the next two years in Alta Energy to acquire, explore, develop and operate onshore unconventional shale operated and non-operated oil and natural gas assets.

No significant legal proceedings are pending which are expected to have a material adverse effect on the Company. The Company is unaware of any potential claims or lawsuits involving environmental, operating or corporate matters which are expected to have a material adverse effect on the Company's financial position or results of operation.

13. Stock Based Compensation

The Company's 1999 Stock Incentive Plan (the "1999 Plan") expired in August 2009. There are 45,000 outstanding options issued under the 1999 Plan which will be converted into securities if exercised prior to their expiration in September 2013.

On September 15, 2009, the Company's Board of Directors (the "Board") adopted the Contango Oil & Gas Company 2009 Equity Compensation Plan (the "2009 Plan"), which was approved by shareholders on November 19, 2009. Under the 2009 Plan, the Board may grant restricted stock and option awards to officers, directors, employees or consultants of the Company. Awards made under the 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board.

Stock Options

Under the 2009 Plan, the Company may issue up to 1,500,000 shares of common stock with an exercise price of each option equal to or greater than the market price of the Company's common stock on the date of grant. The Company may grant key employees both incentive stock options intended to qualify under Section 422 of the Internal Revenue Code of 1986, as amended, and stock options that are not qualified as incentive stock options. Stock option grants to non-employees, such as directors and consultants, can only be stock options that are not qualified as incentive stock options. Options generally expire after five or ten years. The vesting schedule varies, and can vest over a two, three or four-year period. As of June 30, 2011, there were no options outstanding under the 2009 Plan.

A summary of the status of stock options granted under the 1999 Plan and 2009 Plan as of June 30, 2011, 2010 and 2009, and changes during the fiscal years then ended, is presented in the table below:

	Year Ended June 30,					
	2011		2010		2009	
	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price
Outstanding, beginning of year	305,334	$ 28.61	685,167	$ 16.49	855,667	$ 11.57
Granted	-	$ -	25,000	$ 49.29	60,000	$ 50.91
Exercised	(152,544)	$ 21.38	(344,229)	$ 9.24	(230,500)	$ 7.18
Forfeited	(107,790)	$ 28.14	(60,604)	$ 10.20	-	$ -
Outstanding, end of year	45,000	$ 54.21	305,334	$ 28.61	685,167	$ 16.49
Aggregate intrinsic value ($000)	$ 190		$ 4,928		$ 17,814	
Exercisable, end of year	45,000	$ 54.21	240,334	$ 22.74	625,167	$ 13.19
Aggregate intrinsic value ($000)	$ 190		$ 5,290		$ 18,317	
Available for grant, end of year	1,475,000		2,475,000		508,666	
Weighted average fair value of options granted during the year (1)	$ -		$ 15.39		$ 24.91	

(1) The fair value of each option is estimated as of the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions used for grants during the years ended June 30, 2010 and 2009, respectively: (i) risk-free interest rate of 0.25 percent and 3.01 percent; (ii) expected lives of five years; (iii) expected volatility of 35 percent and 53 percent; and (iv) expected dividend yield of zero percent.

The following table summarizes information regarding stock options that were outstanding at June 30, 2011:

	Options Outstanding			Options Exercisable	
Exercise Price	Number of Shares Under Outstanding Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Shares Under Outstanding Options	Weighted Average Exercise Price
$54.21	45,000	2.2	$ 54.21	45,000	$ 54.21

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the fiscal years ended June 30, 2011, 2010 and 2009, approximately $0.5 million, $0.1 million, and $0.3 million, respectively, of such excess tax benefits were classified as financing cash flows. See Note 2 – Summary of Significant Accounting Policies.

Compensation expense related to employee stock option grants are recognized over the stock option's vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model. In November 2010, the Company's Board of Directors approved the immediate vesting of all outstanding stock options under both the 1999 Plan and the 2009 Plan. This accelerated vesting resulted in the Company immediately recognizing stock option expense of approximately $1.1 million. The accelerated vesting and modification affects no other terms or conditions of the options, including the number of outstanding options or exercise price.

Additionally, the Board authorized management to net-settle any outstanding stock options in cash. The option holder has a choice of receiving cash upon net settlement of options or to settle options for shares of the Company. Such modification of the stock options resulted in recognizing a liability equal to the portion of each award attributable to past service multiplied by the modified award's fair value. The initial liability of $0.4 million recognized upon the modification did not exceed the amount of stock option expense which had been previously recognized in equity for the original award and did not result in additional stock option expense but a reduction in equity. Subsequent to the modification, to the extent that the liability exceeds the amount recognized at the end of the previous period, the difference is recognized as compensation cost for each period until the stock options are settled.

The Company recognized an additional $0.1 million in stock option expense related to the liability instruments. This stock option liability of $0.5 million is included in other current liabilities in the Company's Balance Sheet as of June 30, 2011. During the fiscal year-ended June 30, 2011, 2010 and 2009, the Company recognized a total stock option expense of $1.3 million, $0.6 million, and $1.1 million, respectively.

The liability for the outstanding 45,000 stock options is based on the fair value of each award estimated at the end of each quarter using the Black-Scholes option-pricing model. The following assumptions were used in calculating the liability for the 45,000 outstanding options as of June 30, 2011: (i) risk-free interest rate of 0.45 percent; (ii) expected life of 2.2 years; (iii) expected volatility of 22.9 percent and (iv) expected dividend yield of zero percent.

The aggregate intrinsic values of the options exercised during fiscal years 2011, 2010 and 2009 were approximately $8.9 million, $15.3 million, and $12.2 million, respectively.

Restricted Stock

The Company did not grant any shares of restricted stock for the fiscal year ended June 30, 2011 or 2010. For the fiscal year ended June 30, 2009, the Company awarded a total of 3,088 shares of restricted stock under the 1999 Plan to its board of directors. Of these 3,088 shares of restricted stock, 1,544 shares vested on the date of grant, and the remaining 1,544 shares vested one year thereafter. The fair value of restricted stock was approximately $144,000.

For the year ended June 30, 2010 and 2009, the Company recognized approximately $72,000, and $241,000, respectively, in compensation expense relating to restricted stock awards. A summary of the Company's restricted stock as of June 30, 2011, is as follows:

	Number of Shares	**Weighted Average Fair Value Per Share**
Nonvested balance at June 30, 2009	1,544	$ 46.75
Granted	-	-
Vested	(1,544)	46.75
Forfeited	-	-
Nonvested balance at June 30, 2010	-	$ -
Granted	-	-
Vested	-	-
Forfeited	-	-
Nonvested balance at June 30, 2011	-	$ -

14. Related Party Transactions

On May 13, 2011 the Company sold substantially all of its onshore Texas assets to Patara Oil & Gas LLC ("Patara") for an aggregate purchase price of $40 million ($38.7 million after adjustments). The properties were sold effective April 1, 2011 and include: (i) the Company's 90% interest and 5% overriding royalty interest in the 21 wells drilled under a joint venture with Patara; (ii) the Company's 100% working interest (72.5% net revenue interest) in Rexer #1 drilled in south

Texas; and (iii) a 75% working interest (54.4% net revenue interest) in Rexer #2, which was spud on May 11, 2011. B.A. Berilgen, a member of the Company's board of directors, is the Chief Executive Officer of Patara. See Note 6— "Discontinued Operations" for additional information.

As of June 30, 2011, Patara owed the Company approximately $0.5 million related to various prior period adjustments. This amount is included in our accounts receivable balance at June 30, 2011.

In July 2011, the Company's Chairman and CEO, in consultation with the Company's Board of Directors, granted year-end bonuses to all of the Company's employees. Part of this bonus package included approximately $2.9 million of deferred compensation with vesting provisions, to further incentivize employees to remain with the Company. One-half of this amount shall vest and be paid on June 30, 2012 and one-half will vest and be paid on June 30, 2013, as long as the employees are employed by the Company on the vesting date.

During the fiscal year ended June 30, 2011, the Company purchased 172,544 shares of its common stock for a total of approximately $9.8 million. Of this amount, 149,573 shares were purchased from four employees and one member of its board of directors for a total of approximately $8.7 million. During the fiscal year ended June 30, 2010, the Company purchased 115,454 shares of its common stock from three officers of the Company and two members of its board of directors for approximately $6.4 million. During the fiscal year ended June 30, 2009, the Company purchased 21,754 shares of its common stock from one member of its board of directors for approximately $1.3 million. All the purchases were approved by the Company's board of directors and were completed at the closing price of the Company's common stock on the date of purchase.

In March 2006, COE executed a Promissory Note (the "COE Note") to the Company to finance its share of development costs in Grand Isle 72. As of May 31, 2010, COE owed the Company $4.3 million under the COE Note, and an additional $1.6 million in accrued and unpaid interest. Effective June 1, 2010, COE was dissolved and the Company assumed its 65.6% of the obligation of COE, while the other member of COE assumed the remaining 34.4%, or approximately $2.0 million. This $2.0 million is reflected as a note receivable in the Balance Sheet of the Company as of June 30, 2010. The note receivable was paid in full on October 27, 2010.

15. Share Repurchase Program

In September 2008, the Company's board of directors approved a $100 million share repurchase program. All shares are purchased in the open market from time to time by the Company or through privately negotiated transactions. The purchases will be made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock become authorized but unissued shares, and may be issued in the future for general corporate and other purposes. As of June 30, 2011, we had purchased 1,885,441 shares of our common stock at an average cost per share of $45.05, for a total expenditure of approximately $84.9 million. As at June 30, 2011, we had 15,664,666 shares of common stock outstanding and 45,000 options outstanding.

16. Subsequent Events

On August 22 and 23, 2011, the Company repurchased 36,700 shares of its common stock under the share repurchase program described in Note 15 – "Share Repurchase Program", at an average cost per share of $54.91. As of August 29, 2011, we have 15,627,966 shares of common stock outstanding and 45,000 options outstanding.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
SUPPLEMENTAL OIL AND GAS DISCLOSURES (Unaudited)

In accordance with U.S. GAAP for disclosures regarding oil and gas producing activities, and SEC rules for oil and gas reporting disclosures, we are making the following disclosures regarding our natural gas and oil reserves and exploration and production activities.

Costs Incurred. The following table presents information regarding our net costs incurred in the purchase of proved and unproved properties and in exploration and development activities for the periods indicated:

	Year Ended June 30,		
(thousands)	2011	2010	2009
Property acquisition costs:			
Unproved	$ 2,802	$ 11,319	$ -
Proved	10,135	2,009	1,131
Exploration costs	14,016	52,805	23,285
Developmental costs	39,211	40,902	22,890
Total costs incurred	$ 66,164	$ 107,035	$ 47,306

Natural Gas and Oil Reserves. Proved reserves are the estimated quantities of natural gas, oil and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and current regulatory practices. Proved developed reserves are proved reserves which are expected to be produced from existing completion intervals with existing equipment and operating methods.

Proved natural gas and oil reserve quantities at June 30, 2011, 2010 and 2009, and the related discounted future net cash flows before income taxes are based on estimates prepared by William M. Cobb & Associates, Inc. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

The Company's net ownership interests in estimated quantities of proved natural gas, oil and natural gas liquids ("NGLs") reserves and changes in net proved reserves as of June 30, 2011, 2010 and 2009, all of which are located in the continental United States, are summarized below:

	Oil and Condensate	NGLs	Natural Gas
	(MBbls)	(MBbls)	(MMcf)
Proved Developed and Undeveloped Reserves as of:			
June 30, 2008	5,479	7,439	291,568
Sale of minerals in place	-	-	-
Extensions and discoveries	104	69	2,148
Purchases of minerals in place	-	-	-
Revisions of previous estimates	(64)	483	7,437
Production	(515)	(590)	(20,537)
June 30, 2009	5,004	7,401	280,616
Sale of minerals in place	-	-	-
Extensions and discoveries	1,276	1,081	40,635
Purchases of minerals in place	-	-	-
Revisions of previous estimates	(1,177)	(1,146)	(53,855)
Production	(505)	(598)	(21,385)
June 30, 2010	4,598	6,738	246,011
Sale of minerals in place	(126)	(648)	(16,804)
Extensions and discoveries	565	191	31,585
Purchases of minerals in place	53	9	929
Revisions of previous estimates	73	(302)	2,584
Production	(685)	(702)	(26,160)
June 30, 2011	4,478	5,286	238,145

	Oil and Condensate (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)
Proved Developed Reserves as of:			
June 30, 2008	5,479	7,439	291,568
June 30, 2009	5,004	7,401	280,616
June 30, 2010	4,328	6,167	231,260
June 30, 2011	3,738	5,037	205,085
Proved Undeveloped Reserves as of:			
June 30, 2008	-	-	-
June 30, 2009	-	-	-
June 30, 2010	270	571	14,751
June 30, 2011	740	249	33,060

During the fiscal year ended June 30, 2011, the most significant changes to our reserves were associated with our discovery at Vermilion 170 and the sale of our Joint Venture Asset reserves (see Note 6 – "Discontinued Operations").

During the fiscal year ended June 30, 2010, we had a revision of approximately 48.5 Bcfe related to our Dutch and Mary Rose field reserves. As a result of newly learned bottom hole pressure data determined during a recent field wide shut-in and a "P/Z pressure test", our independent third-party engineer concluded that we had less reserves than originally estimated.

Standardized Measure. The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved natural gas and oil reserves as of June 30, 2011, 2010 and 2009 are shown below:

	As of June 30,		
(thousands)	2011	2010	2009
Future cash inflows	$ 1,801,236	$ 1,720,888	$ 1,750,119
Future production costs	(313,688)	(232,641)	(248,468)
Future development costs	(52,053)	(66,237)	(16,226)
Future income tax expenses	(406,306)	(399,755)	(447,935)
Future net cash flows	1,029,189	1,022,255	1,037,490
10% annual discount for estimated timing of cash flows	(312,054)	(310,161)	(399,399)
Standardized measure of discounted future net cash flows	$ 717,135	$ 712,094	$ 638,091

Future cash inflows represent expected revenues from production and are computed by applying certain prices of natural gas and oil to estimated quantities of proved natural gas and oil reserves. As of June 30, 2011, future cash inflows were based on the first-day-of-the-month prices for the previous 12 months of $4.25 per MMBtu of natural gas, $90.27 per barrel of oil, and $55.78 per barrel of natural gas liquids. For the fiscal year ended June 30, 2010, future cash inflows were based on the first-day-of-the-month prices for the previous 12 months of $4.09 per MMBtu of natural gas, $76.21 per barrel of oil, and $44.62 per barrel of natural gas liquids. For the fiscal year ended June 30, 2009, future cash flows were based on fiscal year-end prices of $3.89 per MMBtu for natural gas, $69.89 per barrel of oil, and $35.66 per barrel of natural gas liquids, in each case before adjusting for basis, transportation costs and BTU content.

Future production and development costs are estimated expenditures to be incurred in developing and producing the Company's proved natural gas and oil reserves based on historical costs and assuming continuation of existing economic conditions. Future development costs relate to compression charges at our platforms, abandonment costs, recompletion costs, and additional development costs for new facilities.

Future income taxes are based on year-end statutory rates, adjusted for tax basis and applicable tax credits. A discount factor of 10 percent was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Company's natural gas and oil properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates of natural gas and oil producing operations.

Change in Standardized Measure. Changes in the standardized measure of future net cash flows relating to proved natural gas and oil reserves are summarized below:

	Year Ended June 30,		
(thousands)	**2011**	**2010**	**2009**
Changes due to current year operation:			
Sales of natural gas and oil produced during the period, net of production expenses	$ (188,810)	$ (143,641)	$ (166,971)
Extensions and discoveries	160,712	151,760	9,053
Net change in prices and production costs	5,401	108,883	(2,246,528)
Changes in estimated future development costs	41,989	7,969	5,274
Revisions in quantity estimates	4,078	(190,840)	24,805
Purchase of reserves	6,556	-	-
Sale of reserves	(20,031)	-	-
Accretion of discount	97,044	88,986	318,384
Change in the timing of production rates and other	(96,340)	57,460	(237,995)
Changes in income taxes	(5,558)	(6,574)	698,151
Net change	5,041	74,003	(1,595,827)
Beginning of year	712,094	638,091	2,233,918
End of year	$ 717,135	$ 712,094	$ 638,091

For the fiscal year ended June 30, 2011, the standardized measure increased by approximately $160.7 million which was primarily due to our discovery at Vermilion 170. For the fiscal year ended June 30, 2011 and 2009, the standardized measure decreased by approximately $96.3 million and $238.0 million primarily due to a change in the timing of production rates**.** This is mainly attributable to production profile differences and other imprecise assumptions. We had 11 wells producing in 2011 and nine wells producing in 2010 and 2009.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
QUARTERLY RESULTS OF OPERATIONS (Unaudited)

Quarterly Results of Operations. The following table sets forth the results of operations by quarter for the years ended June 30, 2011 and 2010:

	Quarter Ended			
	Sept. 30,	Dec. 31,	Mar. 31,	June 30,
(thousands, except per share amounts)				
Fiscal Year 2011:				
Revenues from continuing operations	$ 53,097	$ 49,123	$ 52,641	$ 48,917
Income from continuing operations (1)	$ 31,334	$ 15,070	$ 25,282	$ 26,563
Net income (loss) from discontinued operations, net of taxes	$ (877)	$ 2,279	$ 465	$ (286)
Net income attributable to common stock	$ 18,941	$ 11,767	$ 16,796	$ 17,529
Net income per share (2):				
Basic:	$ 1.21	$ 0.75	$ 1.07	$ 1.12
Diluted:	$ 1.20	$ 0.75	$ 1.07	$ 1.12
Fiscal Year 2010:				
Revenues from continuing operations	$ 35,602	$ 46,080	$ 37,223	$ 40,105
Income from continuing operations (1)	$ 21,377	$ 30,838	$ 2,765	$ 26,927
Net income (loss) from discontinued operations, net of taxes	$ -	$ (121)	$ (67)	$ (292)
Net income attributable to common stock	$ 13,466	$ 19,111	$ 1,742	$ 15,367
Net income per share (2):				
Basic:	$ 0.85	$ 1.21	$ 0.11	$ 0.97
Diluted:	$ 0.83	$ 1.18	$ 0.11	$ 0.95

(1) Represents natural gas and oil sales, less operating expenses, exploration expenses, depreciation, depletion and amortization, lease expirations and relinquishments, impairment of natural gas and oil properties, general and administrative expense, and other income and expense before income taxes.

(2) The sum of the individual quarterly earnings per share may not agree with year-to-date earnings per share as each quarterly computation is based on the income for that quarter and the weighted average number of common shares outstanding during that quarter.

Exhibit 21.1

SUBSIDIARIES OF CONTANGO OIL & GAS COMPANY

At June 30, 2011

100% Owned Subsidiaries:

Name of Subsidiary	State or Country in Which Organized
Contango Operators, Inc.	Delaware
Contango Venture Capital Corporation	Delaware
Contango Energy Company	Delaware
Conterra Company	Delaware
Contango Mining Company	Delaware
Contango Alta Investments	Delaware

Partially Owned Subsidiaries:

Name of Subsidiary	State or Country in Which Organized
Republic Exploration LLC (32.3% owned by Contango Operators, Inc.)	Delaware

Exhibit 23.1

WILLIAM M. COBB & ASSOCIATES, INC.

August 29, 2011

Contango Oil & Gas Company
3700 Buffalo Speedway, Suite 960
Houston, Texas 77098

Re: Contango Oil & Gas Company, 2011 Annual Report on Form 10-K

Gentlemen:

The firm of William M. Cobb & Associates, Inc. consents to the use of its name and to the use of its report regarding Contango Oil & Gas Company's Proved Reserves and Future Net Revenues in Contango's Annual Report on Form 10-K for the year ended June 30, 2011.

William M. Cobb & Associates, Inc. has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

Yours very truly,

WILLIAM M. COBB & ASSOCIATES, INC.

/s/ F.J. MAREK

F.J. MAREK, P.E.
Senior Vice President

Exhibit 23.2

LONQUIST & CO. LLC

August 29, 2011

Contango Oil & Gas Company
3700 Buffalo Speedway, Suite 960
Houston, Texas 77098

Re: Contango Oil & Gas Company, Annual Report on Form 10-K

Gentlemen:

The firm of Lonquist & Co. LLC consents to the use of its name and to the use of its projections for Contango Oil & Gas Company's Proved Reserves and Future Net Revenue in Contango's Report on Form 10-K for the year ended June 30, 2011.

Lonquist & Co. LLC has no interests in Contango Oil & Gas Company or in any affiliated companies or subsidiaries and is not to receive any such interest as payment for such reports and has no director, officer, or employee otherwise connected with Contango Oil & Gas Company. Contango Oil & Gas Company does not employ us on a contingent basis.

Yours very truly,

LONQUIST & CO. LLC

/s/ Richard R. Lonquist

RICHARD R. LONQUIST, P.E.

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated August 29, 2011, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of Contango Oil & Gas Company and subsidiaries on Form 10-K for the year ended June 30, 2011. We hereby consent to the incorporation by reference of said reports in the Registration Statement of Contango Oil & Gas Company on Form S-8 (File No. 333-170236, effective October 29, 2010).

/S/ GRANT THORNTON

Houston, Texas
August 29, 2011

Exhibit 31.1

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, Kenneth R. Peak, Chairman and Chief Executive Officer of Contango Oil & Gas Company (the "Company"), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Company;
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 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 Company as of, and for, the periods presented in this report;
4. I am 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 Company and have:
   - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to me 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 my 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 Company's disclosure controls and procedures and presented in this report my 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 Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting; and
5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors (or persons performing the equivalent functions):
   - (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 Company'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 Company's internal control over financial reporting.

Date: August 29, 2011

/s/ KENNETH R. PEAK

Kenneth R. Peak
Chairman and Chief Executive Officer

Exhibit 31.2

CONTANGO OIL & GAS COMPANY

Certification Required by Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934

I, Sergio Castro, Chief Financial Officer of Contango Oil & Gas Company (the “Company”), certify that:

1. I have reviewed this Annual Report on Form 10-K of the Company;
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 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 Company as of, and for, the periods presented in this report;
4. I am 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 Company and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to me 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 my 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 Company’s disclosure controls and procedures and presented in this report my 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 Company’s internal control over financial reporting that occurred during the Company’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting; and
5. I have disclosed, based on my most recent evaluation of internal control over financial reporting, to the Company’s auditors and the audit committee of the Company’s board of directors (or persons performing the equivalent functions):
   (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 Company’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 Company’s internal control over financial reporting.

Date: August 29, 2011

/s/ SERGIO CASTRO

Sergio Castro
Chief Financial Officer

Exhibit 32.1

CONTANGO OIL & GAS COMPANY

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 Contango Oil & Gas Company (the "Company") on Form 10-K for the period ending June 30, 2011 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Kenneth R. Peak, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

Dated: August 29, 2011

/s/ KENNETH R. PEAK

Kenneth R. Peak
Chairman and Chief Executive Officer

Exhibit 32.2

CONTANGO OIL & GAS COMPANY

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 Contango Oil & Gas Company (the "Company") on Form 10-K for the period ending June 30, 2011 (the "Report"), as filed with the Securities and Exchange Commission on the date hereof, I, Sergio Castro, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

Dated: August 29, 2011

/s/ SERGIO CASTRO

Sergio Castro
Chief Financial Officer

Exhibit 99.1

EVALUATION

OF

CERTAIN OIL AND GAS PROPERTIES

LOCATED IN THE

GULF OF MEXICO

PREPARED FOR

CONTANGO OIL & GAS COMPANY

AS OF

JULY 1, 2011

WILLIAM M. COBB & ASSOCIATES, INC.
Worldwide Petroleum Consultants

WILLIAM M. COBB & ASSOCIATES, INC.
Worldwide Petroleum Consultants

12770 Coit Road, Suite 907
Dallas, Texas

(972) 385-(
Fax: (972) 788-5
E-Mail: office@wmcobb.

August 2, 2011

Mr. Kenneth R. Peak
Contango Oil & Gas Company
3700 Buffalo Speedway, Suite 960
Houston, TX 77098

Dear Mr. Peak:

In accordance with your request, William M. Cobb & Associates, Inc. (Cobb & Associates) has estimated the proved reserves and future income as of July 1, 2011, attributable to the interest of Contango Oil & Gas Company and its subsidiaries (Contango) in certain oil and gas properties located in state and federal waters of the Gulf of Mexico. The properties are located in three fields; Eugene Island 10, Ship Shoal 263, and Vermilion 170.

Table 1 summarizes our estimate of the proved oil and gas reserves and their pre-federal income tax value undiscounted and discounted at 10 percent. Values shown are determined utilizing constant oil and gas prices and operating expenses. The discounted present worth of future income values shown in Table 1, or in other portions of this report, are not intended to necessarily represent an estimate of fair market value.

TABLE 1

CONTANGO - NET RESERVES AND VALUE
AS OF JULY 1, 2011
CONSTANT OIL AND GAS PRICES

Reserve Category	Net Gas (MMCF)	Net NGL (MBBL)	Net Oil (MBBL)	Future Net Pre-Tax Income – M$ Undiscounted	Future Net Pre-Tax Income – M$ Discounted at 10%
Proved					
Producing	153,871	3,693	3,256	1,039,641	707,452
Non-Producing	51,214	1,344	482	216,208	100,219
Undeveloped	33,060	249	740	179,646	173,369
Total Proved	238,145	5,286	4,478	1,435,495	981,040

Oil and NGL volumes are expressed in thousands of stock tank barrels (MBBL). A stock tank barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of standard cubic feet (MMCF) as determined at 60° Fahrenheit and the legal pressure base for the specific location of the gas reserves.

The various categories of proved reserves have been combined in certain tables of this report for convenience and/or illustrative purposes. It should be recognized that different levels of risk and uncertainty are associated with these different reserve categories; however, the reserves and revenues presented in this report have not been adjusted for risk.

Our report, which is being filed with Contango's Form 10-K for the fiscal year ended June 30, 2011, covers 296,723 MMCFE, or 100 percent of the total reserves presented in Contango's Form 10-K. We have used all methods and procedures considered necessary under the circumstances to prepare this report.

DISCUSSION

Eugene Island 10

Eugene Island 10 is located in federal and state waters of the Gulf of Mexico. Water depth is approximately 13 feet. Production is primarily from a single CibOp sand, the JRM-1 sand, at a depth of approximately 15,000 feet. The field was discovered in September, 2006 by the Contango Operators Dutch 1. Contango has since drilled three more wells, the Dutch 2, 3 and 4, on Federal acreage. The Dutch 1, 2, and 3 wells produce to the Chevron Eugene Island 24 platform. The Dutch 4 well produces to the Contango 'H' platform.

Contango's Louisiana State leases in this field are referred to as the Mary Rose prospect. Four Mary Rose wells have been drilled to date. All four wells produce to the Contango 'H' platform located in Eugene Island Block 11.

Proved reserves for the Eugene Island 10 CibOp sand are based on a field-wide P/Z performance plot, supplemented by volumetric calculations of original-gas-in-place (OGIP) using all available well log data coupled with 3D seismic data. The reservoir has been effectively drilled to the lowest structural datum and no significant aquifer has been found. A depletion drive system is anticipated. A full-field reservoir simulation model has been constructed and history matched to pressure data from the field. Projections of future gas rates from the simulation model are utilized in this report. Our PDP projection is for the eight wells actually producing on July 1, 2010 using the current platform delivery pressures of 1,050 psi for the Chevron platform and 1,020 psi for the 'H' platform.

PDNP reserves are included for compression, which is scheduled for January, 2014. Delivery pressures with compression will be lowered to 200 psi. Capital costs for installation of the compression are 11,750 M$ for the Chevron platform and 9,100 M$ for the Contango 'H' platform. Fuel charges are calculated based on a volume of 2,000 MCFPD for each platform at the current gas price.

Contango's working interest ownership is approximately 47 percent in the Dutch wells and 53 percent in the Mary Rose 1 through 3 wells. The Contango working interest in the Mary Rose 4 well is approximately 35 percent. Based on future net income, discounted at 10 percent (PV10), approximately 81 percent of the Contango proved reserve value is attributable to the Eugene Island 10 main CibOp reservoir.

The output volumes from the full-field simulator are wet gas volumes only. We have utilized a PVT sample from the Dutch 2 well, along with predicted reservoir pressure values, to convert the wet gas volumes to sales gas, condensate, and NGL volumes.

Contango has drilled two additional wells on the State acreage which produce from gas reservoirs separate from the main CibOp reservoir. The Eloise 3 well has produced and depleted a lower RobL sand. Future recompletions are scheduled for an upper Rob L sand and an isolated CibOp sand. Reserves for the two behind pipe zones are based on volumetric calculations.

The Eloise 5 well has also produced and depleted a lower RobL sand. A recompletion is scheduled to the main CibOp reservoir, at which time this will become the Dutch 5 well.

One future PUD well has been scheduled for the main CibOp reservoir. The Mary Rose 5 well is scheduled to be drilled and on production in April of 2013. This is primarily a rate acceleration well, with very little incremental recovery.

Ship Shoal 263

Contango drilled the Ship Shoal 263 B-1 well in 2010 and completed the well for production in a gas sand at 15,850 feet. The well began producing on June 30, 2010 and has produced approximately 5 BCF of gas and 300 MBBL condensate. The well is currently producing at a rate of about 5 MMCF per day with 350 barrels of condensate. Proved reserves are based on a reservoir simulation model history matched to actual production and pressure performance.

Vermilion 170

Contango drilled the OCS-G-33596 #1 in March of 2011 and successfully completed the well in the Big A sand at a depth of approximately 14,000 feet. Production is scheduled to start in October, 2011 upon installation of a production platform in 87 feet of water. A second, updip well is scheduled for April of 2012. Reserves for both wells are based on volumetric calculations and reservoir simulation, and are classified as PUD pending installation of the production platform.

OIL AND GAS PRICING

Projections of proved reserves contained in this report utilize constant product prices of $4.25 per MMBTU of gas and $90.27 per barrel of oil. These are the average first-of-month prices for the prior 12-month period for Henry Hub gas and West Texas Intermediate (WTI) oil. Appropriate oil and gas pricing differentials and BTU factors were applied to each property. The NGL price was scheduled at 59.2 percent of the oil price for the wells producing to the Chevron platform and 54.6 percent for wells producing to the ‘H’ platform.

OPERATING COSTS

Future operating costs for each of the Contango properties are held constant at current values for the life of each property. Following is a brief description of the operating cost projections for each of the Contango properties:

For the Dutch 1 through 3 wells at Eugene Island 10, Contango pays fees to Chevron for transportation and processing at the EI-24 platform. Based on historical data provided by Contango, the transportation and processing fees are $0.171 per MCF of produced gas and $3.987 per barrel of NGL. Additionally, a fixed operating cost of $189,295 per month per well was scheduled based on historical data provided by Contango. The gas shrinkage factor applied for the removal of NGL’s from the gas stream was 0.9088 MCF of sales gas per MCF of produced gas.

For the Mary Rose 1 through 4 wells, and the Dutch 4 well, which produce to the Contango ‘H’ platform, a total fixed operating cost of $703,771 per month was scheduled along with certain transportation and processing fees. Based on data provided by Contango, transportation and processing fees of $2.753 per barrel of oil and $2.279 per barrel of NGL were scheduled. A gas processing fee of $0.027 per MCF was also scheduled. These same fees apply to the Eloise 3 well which also produces to the Contango ‘H’ platform. Due to recent changes in the oil sales agreement on the Contango ‘H’ platform in early 2011, oil transportation charges were scheduled for 50 percent of the production from all wells producing to the platform except for the Mary Rose 4 and Eloise 3 wells, which were not subject to the new sales agreement. Oil transportation charges were scheduled for 100 percent of the production from the Mary Rose 4 and Eloise 3 wells.

For Ship Shoal 263, a fixed operating cost of $135,390 per month was scheduled based on historical data provided by Contango. Variable costs were also scheduled as follows: $0.036 per MCF of gas, $3.446 per barrel of oil, and $4.049 per barrel of NGL. NGL production is based on a projected yield of 8.909 BBL per MCF and the resulting gas shrinkage factor is 0.9643. NGL price is scheduled as 69.8 percent of the oil price.

There is no actual expense data available for Vermilion 170. As such, we have assumed that the costs will be similar to Ship Shoal 263. We have scheduled the same fixed cost of $135,390 per month and the same variable gas and oil costs. We have not projected any NGL reserves for Vermilion 170.

ECONOMIC PROJECTIONS

Figures 1 and 2 are included to highlight various conclusions regarding the Contango reserves. Figure 1 is a pie chart which shows the distribution reserve volumes and value (PV10) by reserve category for the total proved reserves. Figure 2 presents a projection of future net cash flow versus time for each proved reserve category and for the total proved reserves.

A summary economic projection for the Contango total proved reserves may be found in Table 2. Tables 3 through 15 contain economic projections for the Contango PDP reserves, with Table 3 being a total PDP summary. Similar economic projections for the Contango PDNP reserves may be found in Tables 16 through 30, and for the PUD projections in Tables 31 through 36. All economic evaluations are made without consideration of federal income taxes.

OTHER

Our definition of reserves may be found behind the tab entitled, “Reserve Definitions”. It is similar to and consistent with reserve definitions used throughout the industry. We have not made any field examination of the Contango properties; therefore, operating ability and condition of the production equipment have not been considered. No consideration was given in this report to potential environmental liabilities which may exist, nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices.

In evaluating the information at our disposal concerning this appraisal, we have excluded from our consideration all matters as to which legal or accounting interpretation, rather than engineering, may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering data and such conclusions necessarily represent only informed professional judgments.

The reserves included in this report are estimates only and should not be construed as being exact quantities. The revenues from such reserves and the actual costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the prices actually received for the reserves evaluated in this report, and the costs incurred in recovering such reserves, may vary from the price and cost assumptions used in this report. In any case, estimates of reserves may increase or decrease as a result of future operations.

Titles to the appraised properties have not been examined by William M. Cobb & Associates, Inc., nor has the actual degree of interest owned been independently confirmed. The data used in our evaluation were obtained from Contango Oil and Gas Company, and the nonconfidential files of William M. Cobb & Associates, Inc. and were considered accurate. Basic field performance data, together with our engineering work sheets, are maintained on file in our office.

Sincerely,

WILLIAM M. COBB & ASSOCIATES, INC.
Texas Registered Engineering Firm F-84

Frank J. Marek, P.E.
Senior Vice President

STATE OF TEXAS
FRANK J. MAREK
52939
REGISTERED
PROFESSIONAL ENGINEER

FJM:jf
Attachments