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July 24, 2013

VIA EDGAR

U.S. Securities and Exchange Commission
Division of Corporation Finance
100 F Street, NE
Washington, D.C. 20549
Attn: Anne Parker Nguyen, Branch Chief

Re: Contango Oil & Gas Company
Registration Statement on Form S-4, Filed June 14, 2013, File No. 333-189302
Form 10-K for Fiscal Year Ended June 30, 2012, Filed August 29, 2012, File No. 001-16317
Form 10-Q for Fiscal Quarter Ended March 31, 2013, Filed May 10, 2013, File No. 001-16317

Dear Ms. Nguyen:

Contango Oil & Gas Company ("Contango") hereby responds to the comments of the staff (the "Staff") of the U.S. Securities and Exchange Commission (the "Commission") contained in the letter dated July 11, 2013 (the "Comment Letter") with respect to (i) Contango's Registration Statement on Form S-4 filed with the Commission on June 13, 2013, File No. 333-189302 (the "Registration Statement"), (ii) Contango's Form 10-K for the fiscal year ended June 30, 2012, filed with the Commission on August 29, 2012, File No. 001-16317 (the "Form 10-K") and (iii) Contango's Form 10-Q for the fiscal quarter ended March 31, 2013, filed with the Commission on May 10, 2013, File No. 001-16317 (the "Form 10-Q"). Amendment No. 1 to the Registration Statement is being filed concurrently herewith. For your convenience, each response below corresponds to the italicized comment that immediately precedes it, each of which has been reproduced from the Staff's letter in the order presented. References to "we", "us" or "the Company" refer to Contango. References to "Crimson" refer to Crimson Exploration Inc.

*   *   *

Registration Statement on Form S-4

General

1. *We will not be in a position to accelerate the effectiveness of your registration statement until all outstanding issues related to the review of your Form 10-K for the fiscal year ended June 30, 2012 and Form 10-Q for the fiscal quarter ended March 31, 2013, and any related filings, have been resolved.*

   Response: We acknowledge the Staff's comment and understand that all outstanding issues must be resolved, including comments with respect to the Form 10-K and the Form 10-Q, before the Staff will accelerate the effectiveness of the Registration Statement.

2. *Where comments also could apply to similar or related disclosure that appears elsewhere in the same or another section, please make parallel changes to all affected disclosure. This will eliminate the need for us to repeat similar comments. Also, your response letter should include page number references keying each response to the page of the filing where the responsive disclosure can be found. This will expedite our review of the filing.*

   Response: We acknowledge the Staff's comment and have undertaken to make parallel changes to all applicable sections of the disclosure in the Registration Statement and the Form 10-K in responding to the comments contained in the Staff's letter. We have also included page references to all responsive disclosure.

3. *Each presentation, discussion or report held with or presented by an outside party that is materially related to the transaction, whether oral or written, is a separate report that requires a reasonably detailed description meeting the requirements of Item 4(b) of Form S-4 and Item 1015(b) of Regulation M-A. Please confirm that all material presentations or reports, both oral and written, provided by an outside party have been summarized and that you have filed any written materials, including board books, as exhibits pursuant to Item 21(c) of Form S-4, or revise.*

   Response: In response to the Staff's comment, we confirm that we have provided summaries meeting the requirements of Item 4(b) of Form S-4 and Item 1015(b) of Regulation M-A of all reports, opinions and appraisals materially related to the transaction. Specifically, the fairness opinions received by Contango and Crimson from Petrie Partners Securities, LLC and Barclays Capital, Inc. ("Barclays"), respectively, have been described in appropriate detail pursuant to Item 1015(b) of Regulation M-A in the subsections of the Registration Statement entitled "Opinion of Contango's Financial Advisor" on page 65 of Amendment No. 1 and "Opinion of Crimson's Financial Advisor" on page 81 of Amendment No. 1. We do not believe that any other presentations or reports are material to investors' decisions on the proposed transactions and thus have not been referred to in the prospectus and are not required to be included in the Registration Statement pursuant to Item 4(b).

Background of the Merger, page 50

4. *Please revise your disclosure to indicate why each of Contango and Crimson has chosen to undertake this transaction at this point in time as opposed to other times in each of their operating history. Your disclosure should include the business objectives discussed via telephone on January 9, 2013 and the specific reasons why management of both Contango and Crimson determined that a strategic combination was more advantageous than a joint venture as well as the timing of such determination.*

   Response: In response to the Staff's comment, the disclosure in the Registration Statement on pages 50 and 51 of Amendment No. 1 has been revised.

5. *Please discuss what prompted Crimson's board to review potential strategic alternatives. In addition, please expand your discussion of the other possible strategic alternatives for Crimson discussed with Barclays on January 29, 2013 and by Barclays at the Crimson board meeting on March 12, 2013. Please discuss whether the board pursued any alternative transactions and its reasoning for any such action.*

   Response: In response to the Staff's comment, the disclosure in the Registration Statement on pages 50-52 and page 56 of Amendment No. 1 has been revised.

6. *Please discuss the specific factors considered by Mr. Grady and Mr. Romano in determining a preliminary equity ownership split between Crimson and Contango of 20% and 80%, respectively, on February 5, 2013. In addition, please discuss the "recent events raise regarding equity splits and their combined impact" that resulted in an agreed 79.7/20.3 equity split on April 25, 2013.*

   Response: In response to the Staff's comment, the disclosure in the Registration Statement on pages 52 and 61 of Amendment No. 1 has been revised.

7. *With respect to the March 12, 2013 Crimson board meeting, please expand to discuss in better detail:*
   - *management's "view of the rationale for the proposed strategic combination with Contango,"*
   - *Barclays' "previously-requested review of various possible strategic alternatives for Crimson" and*
   - *Barclays' "preliminary assessment of the possible merger with Contango as one of those alternatives, including discussion of the rationale for the transaction as an alternative that best met Crimson's strategic objectives."*

Response: In response to the Staff's comment, the disclosure in the Registration Statement on page 56 of Amendment No. 1 has been revised.

8. *At page 57, you disclose telephone conversations between March 28 and April 2, 2013 to discuss the merger agreement and support agreements. Please disclose the terms of any drafts and specific terms discussed in negotiations and meetings during this period.*

Response: In response to the Staff's comment, the disclosure in the Registration Statement on page 58 of Amendment No. 1 has been revised. In addition, we respectfully note for the Staff that the telephone conversations in question were internal Crimson conversations amongst Crimson's management team, Crimson's advisors and Crimson's largest shareholder, and that no drafts or specific terms were negotiated between Contango and Crimson pursuant to these conversations.

9. *Please disclose the "factors favorable to Contango that hadn't previously been considered in the analysis" discussed by Mr. Grady and Mr. Romano at the April 22, 2013 meeting. Similarly, please disclose the "factors and information from both Crimson and Contango" referenced in the discussion between Messrs. Keel and Romano on April 25, 2013.*

Response: In response to the Staff's comment, the disclosure in the Registration Statement on page 61 of Amendment No. 1 has been revised.

10. *We note your disclosure at page 77 that in approving the merger, the Crimson board considered that the exchange ratio represented a 7.8% premium to the closing price of Crimson common stock on April 29, 2013. Please disclose any consideration given by Crimson's board to Barclays' notation that "the Merger Consideration was below the implied equity value range per Crimson share yielded by Barclays' research analyst price target analysis" disclosed at page 90. In that regard, please expand your disclosure of the analysis of the proposed exchange ratio and premium associated therewith disclosed by Barclays to Crimson's board on April 27, 2013.*

Response: In response to the Staff's comment, the disclosure in the Registration Statement on page 78 of Amendment No. 1 has been revised. In addition, we respectfully note for the Staff that in connection with the preparation of its opinion, Barclays performed a range of financial, comparative and other analyses, including a net asset valuation analysis, a comparable company analysis, a comparable transactions analysis, a discounted cash flow analysis and, in the case of Crimson, an equity research target price analysis. In connection with its evaluation of the exchange ratio from a financial point of view, the board of directors of Crimson did not assign any particular weight to any single analysis or factor considered by Barclays, but rather considered the totality of the fairness analyses as a whole.

Opinion of Crimson's Financial Advisor, page 80

11. *Please confirm that all financial information and oil and gas reserve reports prepared by Crimson and Contango are summarized in the registration statement or advise.*

    Response: In response to the Staff's comment, we confirm that all financial information and oil and gas reserve reports of Crimson and Contango that were used by Barclays in connection with the preparation of its opinion are summarized in the Registration Statement.

Premium Analysis, page 91

12. *Please identify the precedent transactions that were used by Barclays in the analysis, including the methodology and criteria used in selecting these corporate transactions.*

    Response: In response to the Staff's comment, the disclosure in the Registration Statement on page 93 of Amendment No. 1 has been revised.

Litigation Related to the Merger, page 110

13. *Please supplementally provide us with copies of any amended or consolidated complaints for the lawsuits that have been filed.*

    Response: Several stockholder lawsuits have been consolidated into a single action for all purposes referred to as In Re: Crimson Exploration Inc. Stockholder Litigation, C.A. No. 8541-VCP, and on July 17, 2012, the Delaware Chancery Court entered into an order appointing Lead Plaintiffs, Co-Lead Counsel for Plaintiffs, and Liaison Counsel for Plaintiffs. Under the order, the plaintiffs must file a Consolidated Amended Class Action Complaint (the "Consolidated Complaint") as soon as practicable, however no such complaint has been filed as of the date of this response letter.

    Additionally, on July 13, 2013, a separate and similar complaint was filed in the District Court of Harris County, Texas in the matter of Fisichella Family Trust v. Crimson Exploration Inc. et al (the "Texas Complaint").

    The Texas Complaint has been provided supplementally to the Staff. The Consolidated Complaint will be provided supplementally to the Staff after it has been filed.

    The disclosure in the Registration Statement on pages 112-113 of Amendment No. 1 has been revised accordingly.

Unaudited Pro Forma Condensed Combined Statement of Operations for the Year Ended June 30, 2012, page 143

14. *Send us a reasonably detailed analysis that shows how you calculated the amount of the pro forma adjustment to depreciation, depletion and amortization, as described under note (ix). As part of your response, reconcile the factors for reserve quantities, production volumes and carrying amounts used in the calculation to amounts disclosed elsewhere in either the historical financial statements or pro forma financial information. Note that this comment also applies to the corresponding adjustment included for the interim period ended March 31, 2013.*

Response: In response to the Staff's comment, please find below the requested analysis.

Pro forma adjustments to depreciation, depletion and amortization ("DD&A") cost as described under note (ix) to the Pro Forma Condensed Combined Statement of Operations for the year ended June 30, 2012 and nine months ended March 31, 2013 were calculated as follows:

A. Preliminary Fair Value of property, plant and equipment was allocated between proved and unproved properties and other property and equipment as follows (in thousands):

Proved Properties	**$167,207**
Unproved Properties	**251,984**
Other Property, Plant and Equipment	**1,203**
Total Fair Value - see note (i)	**$420,394**

B. Calculated DD&A rate and pro forma DD&A for the year ended June 30, 2012 based on the historical production and reserves data of Crimson is as follows (Mmcfe):

Total Proved Reserves as of December 31, 2012	**117,049**
Add - Production for the year ended December 31, 2012	**14,126**
Less - Production for the six months ended June 30, 2012	**(7,170)**
Total Proved Reserves as of June 30, 2012	**124,005**
Add - Production for the six months ended June 30, 2012	**7,170**
Add - Production for the year ended December 31, 2011	**16,564**
Less - Production for the six months ended June 30, 2011	**(8,724)**
Total Proved Reserves as of June 30, 2011	**139,015**
Total production for the year ended December 31, 2011	**16,564**
Add - Production for the six months ended June 30, 2012	**7,170**
Less - Production for the six months ended June 30, 2011	**(8,724)**
Total Production for the twelve months ended June 30, 2012	**15,010**
Depletion rate based on total proved reserves	**10.8%**

C. The depletion and the depletion pro forma adjustment for the year ended June 30, 2012 were calculated as follows (in thousands):

Fair Value of Proved Properties acquired	**$167,207**
Depletion rate based on total proved reserves	**10.8%**
Depletion for the year ended June 30, 2012	**$ 18,054**
Less - Crimson's Historical depletion for the twelve months ended June 30, 2012	**$ 58,192**
Adjustment to the DD&A for the year ended June 30, 2012	**$ (40,138)**

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D. The DD&A rate and pro forma DD&A rate for the nine months ended March 31, 2013, based on the historical production and reserves data of Crimson, was calculated as follows (Mmcfe):

Total Proved Reserves as of June 30, 2012 – see note B above	**124,005**
Total Production for the year ended December 31, 2012	**14,126**
Less - Production for the six months ended June 30, 2012	**(7,170)**
Add - Production for the three months ended March 31, 2013	**3,232**
Total Production for the nine months ended March 31, 2013	**10,188**
Depletion rate based on total proved reserves	**8.2%**

E. The depletion and the depletion pro forma adjustment for the nine months ended March 31, 2013 was calculated as follows (in thousands):

Fair Value of Proved Properties acquired	**$167,207**
Less accumulated depletion for the year ended June 30, 2012	**(18,054)**
Value of unamortized proved properties	**149,153**
Depletion rate based on total proved reserves	**8.2%**
Depletion for the nine months ended March 31, 2013	**$ 12,255**
Less - Crimson's Historical depletion for the nine months ended March 31, 2013	**$ 42,466**
Adjustment to the Depreciation, Depletion and amortization for the nine months ended March 31, 2013	**$ (30,211)**

The pro forma decrease in DD&A expenses is primarily caused by negative adjustment to the value of proved reserves based on the preliminary fair value allocation and decrease in the depletion rate due to the calculation of the depletion expenses over total proved reserves rather than over proved reserves for acquisition cost and over proved developed reserves for development costs because fair value of proved properties acquired was classified as acquisition cost in the pro forma combined company balance sheet as of the closing date.

15. *Send us a reasonably detailed analysis that shows how you calculated the amount of the pro forma adjustment to interest expense, as described under note (x). As part of your*

response, reconcile the factors for principal and interest rates to amounts disclosed elsewhere in either the historical financial statements or pro forma financial information. Additionally, explain your basis for the interest rate assumed on the new borrowings. Note that this comment also applies to the corresponding adjustment included for the interim period ended March 31, 2013.

Response: In response to the Staff's comment, please find below the requested analysis.

The pro forma adjustments to the interest expense described under note (x) to the Pro Forma Condensed Combined Statement of Operations for the year ended June 30, 2012 and the nine months ended March 31, 2013 were calculated based on the assumption, as described in note (vi), that immediately subsequent to the closing of the merger, Contango will enter in an amended and restated or new credit facility and use the additional borrowing of $106.9 million under the facility plus cash on hand of $69.9 million to repay the balance of the Second Lien Loan outstanding at the closing date. Accordingly, the pro forma adjustment was calculated based on the assumption that such refinancing and reduction of the balance took place at the beginning of each period presented in the Pro Forma Condensed Combined Statement of Operations. The interest rate on the incremental increase in the Credit Facility was based on a 2.76% historical weighted average interest rate on the First Lien Credit Facility as disclosed in Crimson's Form 10-K for the year ended December 31, 2012.

The adjustment for the year ended June 30, 2012 was calculated as follows (in thousands):

Eliminate interest expense on Second Lien Loan for the year ended June 30, 2012	**$(22,179)**
Eliminate amortization of debt issuance discount for the year ended June 30, 2012	**(1,123)**
Add additional interest expense on increased credit facility (Increase of the borrowings under the facility $106,900 * 2.76% interest rate)	**2,950**
Total adjustment to interest expense for the year ended June 30, 2012	**$(20,352)**

Adjustment for the nine months ended March 31, 2013 was calculated as follows (in thousands):

Eliminate interest expense on Second Lien Loan for the nine months ended March 31, 2013	**$(16,650)**
Eliminate amortization of debt issuance discount for the nine months ended March 31, 2013	**(949)**
Add additional interest expense on increased credit facility (Increase of the borrowings under the facility $106,900 * 2.76% interest rate)	**2,213**
Total adjustment to interest expense for the nine months ended March 31, 2013	**$(15,386)**

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Form 10-K for the Fiscal Year ended June 30, 2012

Offshore Gulf of Mexico Activities, page 2

16. *We note the disclosure of information relating to the Company's daily producing rates on pages 2 and 3, interests owned on page 5, and invested dollar amounts on pages 5 and 6 as of August 24, 2012. Please tell us why the disclosure of such information as of a date after your fiscal year end is relevant and if the disclosed amounts differ materially from those as of June 30, 2012.*

Response: Disclosure of production, ownership and investment information as of a date after our fiscal year end is relevant because it provides the reader with the most up-to-date information available, which reflects any changes to production, ownership, or investments that may have occurred since the fiscal year-end.

The daily producing rates on pages 2 and 3 that we disclosed as of August 24, 2012 are very similar and not materially different from the producing rates as of June 30, 2012.

The interests owned on page 5 that we disclose as of August 24, 2012 are identical to the interests owned as of June 30, 2012.

The invested dollar amounts on pages 5 and 6 that we disclose as of August 24, 2012 are slightly higher than the invested dollar amounts as of June 30, 2012. Footnote Number 15 to the Financial Statements ("Subsequent Events") discloses the dollars invested as of June 30, 2012 as well as the dollars invested as of August 24, 2012.

In response to the Staff's comment, we propose to revise the disclosure on Form 10-K/A to reflect the foregoing. A draft of the Form 10-K/A is provided supplementally for the Staff's consideration. Proposed revisions in response to this comment can be found on page 2 of such draft.

17. *From the disclosure on page 2, we note the Company owns and operates two platforms and two pipelines at Eugene Island 11 that service production from the Company's five Mary Rose wells and the Dutch #4 and #5 wells which are located on other leases. According to the disclosure provided on page 5, the Eugene Island 11 lease expires in December 2012. Under Rule 4-10(a)(22) of Regulation S-X, proved reserves are those*

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quantities of oil and gas which are economically producible prior to the time at which contracts providing the right to operate expire. Please advise or revise your disclosure to clarify your rights to continue operations relating to producing the Mary Rose and Dutch wells through facilities located on Eugene Island 11 after expiration of the Eugene Island 11 lease.

Response: In response to the Staff's comment, we propose to revise the disclosure on Form 10-K/A to indicate that although the Eugene Island 11 block was set to expire in December 2012, this has not, and will not, impact our ability to operate our facilities located on that block. Operators in the Gulf of Mexico may place platforms and facilities on any location without having to own the lease, provided that permission and proper permits from the Bureau of Safety and Environmental Enforcement ("BSEE") have been obtained, and Contango has obtained such permission and permits. We chose to install our facilities at Eugene Island 11 because that was the optimal gathering location given where our wells and marketing pipelines were located, but we were not required to purchase the Eugene Island 11 block to place our facilities there.

A draft of the Form 10-K/A is provided supplementally for the Staff's consideration. Proposed revisions in response to this comment can be found on page 5 of such draft.

Drilling Activity, page 23

18. *We note the Company provides disclosure of its exploratory drilling activity on page 24 as required by Item 1205(a)(1) of Regulation S-K; however, it does not appear that the Company also provides disclosure of its development drilling activity. Please advise or revise your disclosure to comply with the presentation requirements under Item 1205(a)(2) of Regulation S-K.*

Response: In response to the Staff's comment, we propose to revise the disclosure on Form 10-K/A to clarify our disclosure of drilling activity by distinguishing between exploratory and developmental wells. A draft of the Form 10-K/A is provided supplementally for the Staff's consideration. Proposed revisions in response to this comment can be found on page 15 of such draft.

Natural Gas and Oil Reserves, page 25

19. *We note the Company states on page 25 that management is responsible for the reserve estimate disclosures in this filing, and meets regularly with its independent third-party engineer to review these reserve estimates. Please expand your disclosure to provide the qualifications of the technical person within the Company primarily responsible for overseeing the preparation of the reserves estimates consistent with the guidance in Item 1202(a)(7) of Regulation S-K.*

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Response: In response to the Staff's comment, we propose to revise the disclosure on Form 10-K/A to provide the qualifications of the personnel at the Company who are primarily responsible for overseeing the preparation of the reserves estimates. A draft of the Form 10-K/A is provided supplementally for the Staff's consideration. Proposed revisions in response to this comment can be found on page 16 of such draft.

20. *We note that on page 25 the Company discloses its net quantities of proved undeveloped oil and condensate reserves as a negative quantity at June 30, 2012. We find no explanation in your filing on Form 10-K or in the reserves report prepared by William M. Cobb & Associates, Inc. filed as Exhibit 99.1 supporting the disclosure of negative reserve quantities. Rule 4-10(a)(22) of Regulation S-X requires that proved reserves be estimated with reasonably certainty to be economically producible from a given date forward under existing economic conditions. Please clarify for us the basis for the inclusion of negative reserve quantities as proved reserves at June 30, 2012.*

Response: Reserves for the Dutch and Mary Rose CibOp sand are calculated using a number of methods, including static P/Z calculations of original gas in place ("OGIP") and dynamic modeling of historical rates, surface flowing pressures, and shut-in surface and bottom hole pressures. These reservoir simulation models use historical wet gas production data to estimate wet gas production in a given reservoir. "Wet gas" contains both the condensate and natural gas liquids ("NGL"), which are in a gaseous state in the reservoir. Predicted wet gas volumes are then converted to (i) shrunken gas, (ii) condensate, (iii) and NGL volumes. The initial step is to shrink the gas for condensate removal. The condensate yield and shrinkage factor change with declining reservoir pressure. The shrinkage and condensate yield are based on a laboratory fluid sample from the Dutch #2 well. After removal of condensate, the remaining gas stream is "shrunk" again for removal of NGL. The NGL yield and gas shrinkage are calculated from historical lease operating statements provided by Contango.

When the Mary Rose #6 well is factored into the reservoir simulation, the primary effect is the acceleration of wet gas production from the field. The Mary Rose #6 well is projected to recover 34.4 Bcfe over the life of the well. However, 28.2 Bcfe will be recovered by other field wells if the Mary Rose #6 well is not drilled. As such, only 6.2 Bcfe is actually incremental recovery. As the rate acceleration occurs, the pressure depletion trend in the field also changes relative to the continued operations case ("PDP") and the condensate yield is different between the two cases. The incremental projection is obtained by running the total field simulation model with the Mary Rose #6 well and again without the well, and evaluating the difference between the two runs.

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Proved Undeveloped Reserves, page 26

21. *We note from the disclosure on page 26 that the Company annually reviews any proved undeveloped reserves ("PUDs") to ensure their development within five years or less. We also note the Company plans to develop its PUD reserves prior to June 30, 2017 which is five years from the date of the current filing on Form 10-K. For the purposes of determining the five year period for development to occur in estimating proved undeveloped reserves, Item 1203(d) of Regulation S-K requires that you use the date of the initial disclosure as the starting reference date. Please tell us the extent to which any of the proved undeveloped reserves disclosed as of June 30, 2012 will not be developed within five years since your initial disclosure of these reserves. Please also clarify in your disclosure on Form 10-K.*

Response: The Company annually reviews any proved undeveloped reserves ("PUDs") to ensure their development within five years or less. As of June 30, 2012, the Company had approximately 6.2 Bcfe of PUDs related to Mary Rose #6, a rate acceleration well on state of Louisiana acreage. Our plan is to develop our PUD reserves prior to December 31, 2016, which is five years from the initial date of disclosure of these PUD reserves.

As of June 30, 2011, Contango had approximately 39 Bcfe of PUDs. Of this amount, approximately 37.5 Bcfe were attributable to our discovery at Vermilion 170. We announced this discovery in March 2011, but as of June 2011, major completion and facility expenditures were still required to place this well on production. We therefore classified the reserves as PUD as of June 30, 2011. In September 2011, when the expenditures were completed and the well began production, we reclassified a portion of the reserves (11 Bcfe) to proved developed. The total cost to complete the Vermillion 170 facility was approximately $13 million net to Contango. At the time, we believed Vermillion 170 was a water-drive well and that a second well would be required to access the remaining 26.5 Bcfe of reserves. As we obtained more data, we discovered that this was not the case and that the existing well would access all of the reserves. As a result of this information, we reclassified the remaining Vermilion 170 PUD reserves to proved developed in December 2011. No additional capital expenditures were considered necessary to develop the field.

Of the 39 Bcfe of PUDs as of June 30, 2011, approximately 1.5 Bcfe were attributable to reserves in a different zone in our existing Eloise North well. In October 2011, the Company commenced workover operations to plug the Eloise North well in the Rob-L sands, and recomplete up-hole in the CibOp sands. As a result, in December 2011 we reclassified these PUD reserves to proved developed. The total cost of recompletion was approximately $0.3 million net to Contango.

As of June 30, 2010, the Company had approximately 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 properties were sold on May 13, 2011.

In response to the Staff's comment, we propose to revise the disclosure on Form 10-K/A to reflect the foregoing. A draft of the Form 10-K/A is provided supplementally for the Staff's consideration. Proposed revisions in response to this comment can be found on page 17 of such draft.

22. *We note from the disclosure provided on page 23 the Company did not drill any wells during the fiscal year ended June 30, 2012. However, we note on page 26 the Company states it has approximately 6.2 Bcfe of PUDs as of June 30, 2012; whereas, it had approximately 39 Bcfe of PUDs as of June 30, 2011. The net quantity of PUDS from June 30, 2011 has been reduced by 32.8 Bcfe as of June 30, 2012 without an explanation for the material change in proved undeveloped reserves that occurred during the year as required in Item 1203(b) of Regulation S-K. Please advise or revise Form 10-K to include the required disclosure under Item 1203(b) of Regulation S-K.*

Response: Please see the response to comment #21 above.

23. *We also note the Company does not appear to provide disclosure under Item 1203(b) of the net quantities converted from proved undeveloped to proved developed or the capital expenditures associated with converting such reserves to proved developed during the year as required under Item 1203(c) of Regulation S-K. Please advise or revise Form 10-K to include the required disclosures under Item 1203 (b) and Item 1203(c) of Regulation S-K.*

Response: Please see the response to comment #21 above.

Reserve Replacement, page 32

24. *We note the discussion of reserve replacement under this section, as well as the discussion on page 1 of your filing regarding your "core belief" in the importance of the successful drilling of exploratory wells. Separately, we note the disclosure on page 24 indicating that you did not drill any wells during the fiscal year ended June 30, 2012. Revise your disclosure under this section or elsewhere in your MD&A to explain the reasons why you did not drill any wells during this period. Additionally, to the extent that there are known drilling trends that have had or you reasonably expect will have a material impact on your net sales or revenues or income from continuing operations, discuss whether and the extent to which these trends will continue and the impact if they do.*

Response: In response to the Staff's comment, we propose to revise the disclosure on Form 10-K/A to explain why the Company did not drill any wells during fiscal year 2012. A draft of the Form 10-K/A is provided supplementally for the Staff's consideration. Proposed revisions in response to this comment can be found on page 19 of such draft.

<u>Results of Operations, page 33</u>

25. *We note your disclosure of the Company's total annual production volumes for each of the last three years on page 34 and the quarterly average daily production from your offshore wells for the last year on page 33. Please expand your disclosure to include production by final product sold for each field that contains 15% or more of your total proved reserves for the last three years. Refer to Item 1204(a) of Regulation S-K.*

Response: In response to the Staff's comment, we propose to revise the disclosure on Form 10-K/A to provide disclosure of production by final product sold for each field that contains 15% or more of the Company's total production for the last three years. A draft of the Form 10-K/A is provided supplementally for the Staff's consideration. Proposed revisions in response to this comment can be found on page 21 of such draft.

<u>Note 13. Related Party Transactions, page F-16</u>

26. *Explain to us how you account for the overriding royalty interests conveyed to JEX employees.*

Response: Contango has historically used Participation Agreements to document the allocation of interests, including working and overriding royalty interests, in the oil and gas properties to each respective party. Such agreements are usually signed at the beginning of the joint exploration activities in conjunction with the acquisition of the prospect from either JEX or Republic Exploration ("REX") and prior to any proved reserves being identified for the properties. Participation Agreements for each of our fields include provisions which require the Company to (a) carry JEX or REX, and (b) assign overriding royalty interest to JEX employees as part of the consideration for the prospect, in addition to the prospect fees paid to JEX or REX. No accounting for conveyance of overriding royalty interests to JEX employees is required due to the fact that the Company initially acquired the prospect burdened by those overrides.

<u>Exhibit 99.1</u>

27. *We note the reserves report does not include certain disclosures required by Item 1202(a)(8) of Regulation S-K. Please advise the engineering firm that you will need an amended reserves report to include the following information in order to satisfy your filing obligations.*

- *The date on which the report was completed (in addition to the effective date) (Item 1202(a)(8)(ii)).*
- *A statement as part of the assumptions that the estimates were prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas (Item 1202(a)(8)(iv)).*

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- *A statement that the assumptions, data, methods and procedures used in the preparation of the report are appropriate for the purpose served by the report (Item 1202(a)(8)(iv)).*
- *The average realized prices by product for the reserves included in the report as part of the primary economic assumptions (Item 1202(a)(8)(v)).*
- *A discussion of the possible effects of regulation on the ability of the Company to recover the estimated reserves (Item 1202(a)(8)(vi)).*

Response: The Amended Report, included with the draft Form 10-K/A, will be filed as Exhibit 99.1 on Form 10-K/A and will include the aforementioned information.

28. *We note the reserves report refers to the total proved reserves for the fiscal year ended June 30, 2012 in MMcfe. Please obtain and file an amended reserves report that addresses the guidance contained in Instruction 3 to Item 1202(a)(2) of Regulation S-K which requires disclosure of the basis for such equivalency.*

Response: The Amended Report, to be filed as Exhibit 99.1 on Form 10-K/A, has been amended to clarify that the total proved MMcfe as of July 1, 2012 is 256,564,984, which was calculated using a 6 MCF per barrel ratio applied to the condensate and NGL volumes.

29. *We note the reserves report states PDNP reserves are included at Eugene Island 10 for compression. We also note compression is scheduled for June 2013 at a total capital cost of $18,032,000. Please refer to the definition of developed oil and gas reserves set forth in Rule 4-10(a)(6) of Regulation S-X and tell us why the volumes attributable to the installation of compression are disclosed as proved developed (non-producing) rather than proved undeveloped.*

Response: The Contango H platform was designed and fitted for compression prior to installation. Final installation of compression is, in the opinion of the Company and of Cobb, a minor cost in the relative scale of the project. The total estimated cost of compression is approximately $18 million, or $1.8 million per well. The total cost to drill and complete existing producing wells and facilities in the field was approximately $381 million, or $38.1 million per well. The average cost to drill and complete each of the 10 wells in the field was $29.5 million. The $1.8 million cost per well for compression is minor in comparison to the total and per well cost of developing the field.

The compression reserves are low risk, resulting from simply lowering the surface delivery pressure of the existing producing wells. There is little or no geological or mechanical risk associated with these reserves. Therefore, in the opinion of the Company and of Cobb, the compression reserves are appropriately categorized as PDNP reserves.

30. *We note the reserves report states that the Mary Rose #6 location is primarily a rate acceleration well with very little incremental recovery. Please tell us if the 6.2 Bcfe of proved undeveloped reserves disclosed on page 26 of Form 10-K for the Mary Rose #6 is entirely attributable to incremental recovery.*

    Response: Yes. The 6.2 Bcfe reserves for the Mary Rose #6 well are incremental. The Mary Rose #6 well is projected to recover 34.4 Bcfe over the life of the well, but only 6.2 Bcfe is incremental. The remaining 28.2 Bcfe will be recovered by other wells in the field if the Mary Rose #6 well is not drilled. The 28.2 Bcfe is the acceleration recovery from the Mary Rose #6 well.

31. *We note several references to additional information such as the reserves definitions, figures 1 and 2, and tables 2 through 34 that are not included in the reserves report. Please advise or obtain an amended reserves report that includes the referenced information as attachments to Exhibit 99.1.*

    Response: Pursuant to conversations with the Staff, the reserves report has been amended to remove such references while providing additional information and clarity in the body of the Amended Report.

<u>Form 10-Q for the Quarterly Period ended March 31, 2013</u>

<u>Ship Shoal 263 Platform, page 19</u>

32. *Disclosure under this section indicates that you have reclassified the Ship Shoal platform to unproved properties as of March 31, 2013. Explain to us, in reasonable detail, your basis for this accounting. As part of your response, provide reference to the specific accounting literature that supports the reclassification. Additionally, tell us the carrying value of the platform and, separately, the Ship Shoal 263 well as of March 31, 2013.*

    Response: In June 2012, Contango was an apparent high bidder in the Federal Lease Sale for the Ship Shoal 255 lease block, which was awarded to the Company in December 2012. The economics of the Ship Shoal 255 development included utilization of the platform located at lease block Ship Shoal 263. In early 2013, Contango's Board of Directors decided that the Ship Shoal 255 prospect was to be the first well to be drilled in 2013, and the permitting process was initiated with BSEE. By December 31, 2012, the value of Ship Shoal 263 field was impaired due to downward reserve revisions recognized in the first and second quarter of fiscal year 2013. The value of the platform located in the Ship Shoal 263 block was not considered to be impaired due to the potential of its value being recovered from the Ship Shoal 255 field, if such well is successful. In accordance with ASC 932-360-25-3 under the successful efforts

method of accounting, certain types of costs may be capitalized as construction-in-progress pending further information about the existence of future benefits, but as soon as the additional information becomes available, and it is known whether such future benefits exist, those costs are either reclassified as an amortizable asset or charged to expense.

In accordance with ASC 932-360-25-6 the Company may recognize as assets all of the following: unproved properties; proved properties; wells and related equipment and facilities; support equipment and facilities used in oil- and gas-producing activities; uncompleted wells, equipment, and facilities. Historically, the Company did not separately present uncompleted wells, related equipment or facilities on its balance sheet, but rather included such wells and facilities either in proved or unproved properties balance sheet line items depending on the classification of the underlying reserves. Therefore, when the Company determined that the platform located on the Ship Shoal 263 block would be primarily used by Ship Shoal 255 field, which was classified as unproved as of March 31, 2013, the platform was also reclassified to unproved properties as of March 31, 2013 to align with the classification of the property from which the platform value would be recovered.

As of March 31, 2013 the carrying value of the Ship Shoal 263 field and platform located at Ship Shoal 263 reclassified to Ship Shoal 255 field were approximately $62,000 and $14.1 million, respectively. The Company anticipates to spud Ship Shoal 255 well in October 2013. The permitting for this well is in process and the rig contract is in place.

Natural Gas and Oil Reserves, page 27

33. *For the nine months ended March 31, 2013, you disclose downward revisions in your previous proved reserves estimates for the Dutch and Mary Rose leases and Vermilion 170 of 19.2 and 14.0 Bcfe respectively due to additional pressure data. We note you previously disclosed a downward revision in the June 30, 2012 Form 10-K of 48.5 Bcfe in your Dutch and Mary Rose proved reserves estimates due to pressure data for the fiscal year ended June 30, 2010.*

Please provide us with a narrative describing:

- *the methods you used to estimate your proved reserves at June 30, 2012 for the Dutch and Mary Rose leases and Vermilion 170,*
- *why you considered your estimates for these fields to be reasonably certain at the time of disclosure,*
- *why subsequent performance including additional pressure data caused you to make material downward revisions to your previous estimates, and*
- *why you consider your estimates for these fields to be reasonably certain as of March 31, 2013.*

Response: The Dutch/Mary Rose CibOp sand is a thick, stratified gas reservoir at a depth of about 15,350 feet. There are nine producing wells in the main CibOp reservoir, each with extensive rate and flowing surface pressure data available on a daily basis. The tenth well is in a separate, smaller reservoir. Shut-in pressures in this reservoir are much less frequent with very few actual bottom-hole measurements. Most of the bottom hole pressure data in the reservoir is extrapolated from shut-in surface pressures. There has been only one period of total field shut-in, which was in August, 2012. All other well shut-in pressure measurements were taken while other field wells were flowing. The CibOp reservoir simulation model was history matched to the well production and FTP data for the entire field life. The final history match was quite good on an individual well basis. The static P/Z analysis indicates an OGIP value similar to that in the reservoir simulation model.

The reserve reduction at Dutch/Mary Rose in our April 1, 2013 report is attributed to refinement of the individual well bottom hole pressure trends as a result of added pressure data, primarily in the static, P/Z analysis. Individual well rates and flowing pressure trends continue to track the predictions from the dynamic reservoir simulation model.

The Vermilion 170 well produces from a gas reservoir at a depth of approximately 13,800 feet. Original geological maps indicated that this would be a water drive reservoir with significant updip attic reserves. Earlier reserve reports scheduled a second well as a PUD to produce the attic reserves. The well has now produced over 8 BCF of gas and pressure data is indicating a depletion drive system with a lower gas-in-place than indicated by the original maps. Reserves are currently based on a P/Z curve with somewhat limited data and a dynamic simulation model with a very good history match to available daily rate and flowing tubing pressure data.

Current reserves for both the Eugene Island 10 and Vermilion 170 properties are based on the latest available performance data. As such, no reserve revisions, up or down, are anticipated at this time.

* * *

In connection with this response to the Staff's comments, Contango acknowledges that:

- Contango is responsible for the adequacy and accuracy of the disclosure in the filing;
- Staff comments or changes to disclosure in response to Staff comments do not foreclose the Commission from taking any action with respect to the filing; and
- Contango may not assert Staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

If you have any questions or wish to discuss any of the above matters in greater detail, please contact me at (713) 960-1901.

Sincerely,

/s/ Joseph J. Romano

Joseph J. Romano
Chairman, President and Chief Executive Officer

cc:

DRAFT

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

Form 10-K/A
(Amendment No. 1)

(Mark One)

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

For the fiscal year ended June 30, 2012

or

☐ **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 **(State or other jurisdiction of incorporation or organization)**	**95-4079863** **(I.R.S. Employer Identification No.)**

3700 Buffalo Speedway, Suite 960
Houston, TX 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 $.04 per share	**NYSE MKT**

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

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

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

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

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐

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

As of December 31, 2011, the aggregate market value of the registrants common stock held by non-affiliates (based upon the closing sale price of shares of such common stock as reported on the NYSE MKT was $745,499,902. As of August 24, 2012, there were 15,292,448 shares of the registrants common stock outstanding.

EXPLANATORY NOTE

Contango Oil & Gas Company (the “Company”, “Contango”, “we”, “our”, “us”) is hereby amending its previously filed Annual Report on Form 10-K for the fiscal year ended June 30, 2012 (the “Original Filing”). This Amendment No. 1 (the “Amendment”) is being filed solely to amend the following items:

- Item 1 (“Business”) has been revised to clarify the Company’s rights to continue operations of facilities located on Eugene Island 11 following the expiration of the Eugene Island lease in December of 2012.

- Item 2 (“Properties”) has been revised to: (i) clarify its disclosure of drilling activity by distinguishing between exploratory and developmental wells; (ii) provide the qualifications of the personnel at the Company who are primarily responsible for overseeing the preparation of the reserves estimates; (iii) clarify the basis for the inclusion of negative reserve quantities as proved reserves; (iv) clarify that the 6.2 Bcfe of proved undeveloped reserves attributable to the Mary Rose #6 well will be developed within five years of their original disclosure; (v) explain the material change in proved undeveloped reserves that occurred between June 30, 2011 and June 30, 2012; and (vi) explain why the Company did not drill any wells during fiscal year 2012.

- Item 7 (“Management’s Discussion and Analysis of Financial Condition and Results of Operations”) has been revised to provide disclosure of production by final product sold for each field that contains 15% or more of the Company’s total production for the last three years.

- Exhibit 99.1 in Item 15 (“Exhibits and Financial Statement Schedules”) has been refiled to include an amended version of the Report of William M. Cobb & Associates, Inc. that was filed as Exhibit 99.1 to the Original Filing.

This Amendment should be read in conjunction with the Original Filing. This Amendment does not reflect events that occurred after the filing date of the Original Filing and no revisions are being made to the Company’s financial statements pursuant to this Amendment. Other than the filing of the information identified above, this Amendment does not modify or update the disclosure in the Original Filing in any way.

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 onshore and 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 properties.

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 the exploration of i) offshore Gulf of Mexico prospects and ii) conventional and unconventional onshore plays. Exploration prospects are inherently risky as they require large amounts of capital with no guarantee of success. COI drills and operates our 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 ten 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.

Exploration Alliance with JEX

JEX is a private company formed for the purpose of generating offshore and onshore domestic natural gas and oil prospects. Additionally, JEX can generate offshore prospects through our 32.3% owned affiliated company, Republic Exploration LLC ("REX"). In addition to generating new prospects, JEX occasionally evaluates offshore and onshore exploration prospects generated by third-party independent companies for us to purchase. Once we have purchased a prospect from JEX, REX or a third-party, we have historically entered into participation agreements and joint operating agreements, which specify each participant's working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest of up to 3.33% to benefit employees of JEX. See Note 13 - Related Party Transactions for a detailed description of our transactions with JEX and REX.

On April 10, 2012, the Company announced that Mr. Brad Juneau, the sole manager of the general partner of JEX, had joined the Company's board of directors and that the Company had entered into an advisory agreement with JEX (the "Advisory Agreement"), whereby in addition to generating and evaluating offshore and onshore exploration prospects for the Company, JEX will direct Contango's staff on operational matters including drilling, completions and production. Pursuant to the Advisory Agreement, JEX will be paid an annual fee of $2 million and JEX, or employees of JEX, will continue to be eligible to receive overriding royalty interests, carried interests and certain back-in rights.

Offshore Gulf of Mexico Activities

Contango, through its wholly-owned subsidiary, COI and its partially-owned affiliate, REX, conducts exploration activities in the Gulf of Mexico. COI 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 REX, JEX and/or other third parties. In order to provide the most up-to-date information available, where possible we have provided data below as of the most recent practicable date prior to the date of the Original Filing.

As of August 24, 2012, the Company's offshore production was approximately 83.5 million cubic feet equivalent per day ("Mmcfed"), net to Contango, which consists mainly of seven federal and five state of Louisiana wells in the shallow waters of the Gulf of Mexico. These 12 operated wells produce via the following four platforms:

Eugene Island 24 Platform

This third-party owned and operated production platform at Eugene Island 24 was designed with a capacity of 100 million cubic feet per day ("Mmcfd") and 3,000 barrels of oil per day ("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. As of August 24, 2012, we were producing approximately 22.5 Mmcfed, net to Contango, from this platform.

The Company recently finished laying 6" auxiliary flowlines from the Dutch #1, #2, and #3 wells to our Eugene Island 11 Platform (see below) and is in the process of redirecting production from the Eugene Island 24 Platform to the Eugene Island 11 Platform. Our cost estimate for the installation of these three flowlines is $2.5 million, net to Contango. As of June 30, 2012, the Company had incurred approximately $0.8 million to install these flowlines.

Eugene Island 11 Platform

Our Company-owned and operated platform at Eugene Island 11 was designed with a capacity of 500 Mmcfd and 6,000 bopd. In September 2010 the Company installed 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 five Mary Rose wells which are all located in state of Louisiana waters, as well as our Dutch #4 and Dutch #5 wells which are both located in federal waters. From these platforms, we can flow our gas to an American Midstream pipeline via our 8" pipeline and from there to a third-party owned and operated on-shore processing facility at Burns Point, Louisiana. We can 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. As of August 24, 2012, we were producing approximately 44.6 Mmcfed, net to Contango, from this platform.

Based on production and decline rates, the Company has recently determined the need to place its Dutch and Mary Rose wells on compression in 2013. The Company is in the process of designing and building a large turbine type compressor for the platform at an estimated cost of $6.8 million, net to Contango. This compressor will be of sufficient capacity to service all ten of the Company's Dutch and Mary Rose wells. As of June 30, 2012, the Company had incurred approximately $2.3 million to design and build the compressor, which is expected to be installed in June 2013.

Ship Shoal 263 Platform

Our Company-owned and operated platform at Ship Shoal 263 was designed with a capacity of 40 Mmcfd and 5,000 bopd. This platform services natural gas and condensate production from our Nautilus well, which flows via the Transcontinental Gas Pipeline to onshore processing plants. As of August 24, 2012, we were producing approximately 3.0 Mmcfed, net to Contango, from this platform.

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.

Vermilion 170 Platform

Our Company-owned and operated platform at Vermilion 170 was designed with a capacity of 60 Mmcfd and 2,000 bopd. This platform services natural gas and condensate production from our Swimmy well, which flows via the Sea Robin Pipeline to onshore processing plants. As of August 24, 2012, we were producing approximately 13.4 Mmcfed, net to Contango, from this platform.

Based on current production and decline rates, the Company has determined the need to place its Vermilion 170 well on compression in 2013, at a cost of $1.4 million, net to Contango. As of June 30, 2012, the Company had incurred approximately $0.4 million to design and build a compressor to service its Swimmy well, which is expected to be completed in late 2012.

Other Activities

On July 10, 2012 we spud our South Timbalier 75 prospect ("Fang") with the Spartan 303 rig. The Company farmed-in this prospect in August 2011 from an independent third party. We have a 100% working interest in this wildcat exploration prospect, subject to back-ins if successful, and have budgeted to invest approximately $28.0 million to drill this well. As of June 30, 2012, the Company had invested approximately $0.4 million in Fang, which includes leasehold costs.

On July 3, 2012, we spud our Ship Shoal 134 prospect ("Eagle") with the Hercules 205 rig. The Company purchased the deep mineral rights on Ship Shoal 134 from an independent third-party effective February 24, 2011. We have a 100% working interest in this wildcat exploration prospect, subject to back-ins if successful, and have budgeted approximately $25.0 million to drill this well. As of June 30, 2012, the Company had invested approximately $6.5 million in Eagle, which includes leasehold costs. We expect to know the drilling results of both the Eagle and Fang wells by November 2012.

On June 20, 2012, the Company was the apparent high bidder on six lease blocks at the Central Gulf of Mexico Lease Sale 216/222. The Company bid an aggregate amount of approximately $11 million on the following six blocks:

- East Cameron 124
- Eugene Island 31
- Eugene Island 260
- Ship Shoal 83
- Ship Shoal 255
- South Timbalier 110

An apparent high bid ("AHB") is subject to Outer Continental Shelf ("OCS") Bid Adequacy Review. The Bureau of Ocean Energy Management ("BOEM") (formerly the Minerals Management Service) may reject all bids for a given tract. The BOEM review process can take up to 90 days. Upon approval from the BOEM, our plan is to promptly obtain permits to drill these prospects and to drill them in 2013 and 2014. The Company will have a 100% working interest in these prospects, subject to back-ins if successful. In August 2012, the Company was notified that it had been awarded East Cameron 124, Eugene Island 31, Ship Shoal 83 and South Timbalier 110 effective September 1, 2012.

On March 1, 2012, the Company was awarded Brazos Area 543 by the BOEM, which was bid on at the Western Gulf of Mexico Lease Sale No. 218 held on December 14, 2011. As of June 30, 2012, the Company had invested approximately $0.4 million in Brazos Area 543, which includes leasehold costs.

In June 2011, we completed a workover of our Eloise North well at a cost of approximately $1.8 million, net to Contango, which enabled us to continue producing from the lower Rob-L sands. In October 2011, we commenced a workover of our Eloise North well to recomplete the well in the upper Rob-L sands. During the workover, the Company experienced difficulties and unexpected delays due to malfunctioning production tree valves, coiled tubing equipment failures, weather delays, and stuck equipment in the tubing. As a result, the Company plugged the Rob-L sands in January 2012 and recompleted uphole in the Cib-Op sands as our Mary Rose #5 well, at a cost of approximately $0.5 million, net to Contango, based on the new higher ownership percentage and inclusive of a required well cost adjustment. The Mary Rose #5 well began producing on January 26, 2012 and by mid-March 2012 had stopped again. We are currently flowing the well intermittently until we can install compression in 2013.

On December 21, 2011, the Company purchased an additional 3.66% working interest (2.67% net revenue interest) in Mary Rose #5 (previously Eloise North) for approximately $0.2 million from an existing partner. This purchase brings the Company's working interest and net revenue interest in Mary Rose #5 to 37.80% and 27.59%, respectively.

In July 2011, we recompleted our Eloise South well uphole in the Cib-Op sands as our Dutch #5 well, at a cost of approximately $5.7 million, net to Contango. The Company has a 47.05% working interest (38.1% net revenue interest) in Dutch #5. In addition to this $5.7 million, the Dutch #5 well owners purchased the Eloise South well bore from the Eloise South well owners (the "Well Cost Adjustment"). The Company invested a net of approximately $2.3 million related to this Well Cost Adjustment.

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.

Republic Exploration LLC

In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of REX, an entity owned 34.4% by JEX, 32.3% by Contango, and 33.3% by a third party which contributed other assets to REX. REX generates and evaluates offshore exploration prospects and has historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specify each participant's working interest, net revenue interest, and describe when such interests are earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidates the results of REX in its consolidated financial statements.

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 24, 2012, the well was in the process of being recompleted uphole, at a cost of approximately $0.1 million, net to Contango. REX has a 25.0% working interest ("WI"), and a 20.0% net revenue interest ("NRI"), in this well.

Contango Offshore Exploration LLC

Prior to its dissolution on June 1, 2010, in his capacity as sole manager of the general partner of JEX, Mr. Juneau controlled the activities of Contango Offshore Exploration LLC ("COE"), an entity then owned 65.63% by Contango and 34.37% by JEX. COE generated and evaluated offshore exploration prospects and had historically participated with the Company in the drilling and development of certain prospects through participation agreements and joint operating agreements, which specified each participant's working interest, net revenue interest, and described when such interests were earned, as well as allocate an overriding royalty interest ("ORRI") of up to 3.33% to benefit the employees of JEX. The Company proportionately consolidated the results of COE in its consolidated financial statements.

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 JEX 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.

Offshore Properties

During the fiscal year ended June 30, 2012, State Lease 19396 expired and was returned to the state of Louisiana. During the fiscal year ended June 30, 2011, the Company relinquished 12 lease blocks to the BOEM, and allowed two additional lease blocks to expire in accordance with their terms.

Producing Properties. The following table sets forth the interests owned by Contango through its affiliated entities in the Gulf of Mexico which were capable of producing natural gas or oil as of August 24, 2012:

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 and S-L 19261 (Mary Rose #5)	37.80%	27.6%	Intermittent
Ship Shoal 263 (Nautilus)	100.00%	80.0%	Producing
Vermilion 170 (Swimmy)	87.24%	68.0%	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, 2012:

Area/Block	WI	Lease Date	Expiration Date
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
Brazos Area 543	100.00%	Mar-12	Mar-17
Ship Shoal 134	100.00%	(3)	(3)
South Timbalier 75	100.00%	(4)	(4)

(1) Dry Hole
(2) Farm-out. COI retains a 2.41% ORRI
(3) Purchased deep rights. Currently drilling
(4) Farm-in. Currently drilling. Will earn lease once production begins (if successful)

The Eugene Island 11 block expires in December 2012, but this will not impact our ability to operate our facilities located on that block. Operators in the Gulf of Mexico may place platforms and facilities on any location without having to own the lease, provided that permission and proper permits from the Bureau of Safety and Environmental Enforcement (“BSEE”) have been obtained, and Contango has obtained such permission and permits. We chose to install our facilities at Eugene Island 11 because that was the optimal gathering location given where our wells and marketing pipelines were located, but we were not required to purchase the Eugene Island 11 block to place our facilities there.

Onshore Exploration and Properties

Alta Investments

On April 12, 2011, the Company announced a commitment to invest up to $20 million over two years in Alta Energy Canada Partnership (“Alta Energy”), a venture that will acquire, explore, develop and operate onshore unconventional oil and natural gas shale assets. As of August 24, 2012, we had invested approximately $12.3 million in Alta Energy to purchase over 60,000 acres in the Kaybob Duvernay, a liquids rich shale play in Alberta, Canada. Alta Energy has built one of the largest acreage blocks in the core of the play. Alta Energy drilled and cored its first vertical well in 17 days which is highly competitive with offset operators. Alta Energy has drilled three vertical test wells and has taken whole cores on two of those.

Offsetting activity in the Kaybob Duvernay continues to provide encouraging early results. With four horizontal well results available, initial production began with 508 barrels of oil equivalent per day (“Boed”) for the first well and continuously improved to 2,123 Boed for the fourth well which tested 7.7 MMcfd and 839 Bbls per day. Condensate yields continue to rise to close to 100 bbls/MMcf plus encouraging amounts of NGL’s. We expect an active summer of offsetting activity with additional information being slowly provided by competitors to the market. Alta Energy began its summer drilling program which included spudding Alta's first horizontal well. Contango has a 2% interest in Alta Energy and a 5% interest in the Kaybob Duvernay project.

Exaro Energy III LLC

On April 9, 2012, the Company announced that through its wholly-owned subsidiary, Contaro Company, it had entered into a Limited Liability Company Agreement (the "LLC Agreement") to form Exaro Energy III LLC ("Exaro"). Pursuant to the LLC Agreement, the Company has committed to invest up to $82.5 million in cash in Exaro over the next five years together with other parties for an aggregate commitment of $182.5 million. The Company owns approximately a 45% interest in Exaro, subject to terms allowing another party to acquire up to $15 million of the Company's commitment, which would decrease the Company's interest in Exaro to approximately 37%.

As of June 30, 2012, the Company had invested approximately $41.3 million in Exaro. Exaro has entered into an Earning and Development Agreement (the "EDA Agreement") with Encana Oil & Gas (USA) Inc. ("Encana") to provide funding of up to $380 million to continue the development drilling program in a defined area of Encana's Jonah field asset located in Sublette County, Wyoming. This funding will be comprised of the $182.5 million investment detailed above, debt, and cash flow from operations. Encana will continue to be the operator of the field and upon investing the full amount of the $380 million, Exaro will have earned 32.5% of Encana's working interest in a defined joint venture area that comprises approximately 5,760 gross acres.

The Exaro-Encana venture currently has three rigs drilling, has completed five wells to date and achieved first production during mid-June 2012. The drilling project is progressing on schedule. As of June 30, 2012, there were no material natural gas or oil reserves associated with our investment in Exaro. During the period from inception to June 30, 2012, Exaro incurred a loss of approximately $1.5 million, of which approximately $0.5 million was recognized in the Company's consolidated statement of operations (net of $0.2 million in taxes) for the fiscal year ended June 30, 2012.

Tuscaloosa Marine Shale

As of August 24, 2012, the Company had invested approximately $8.7 million to lease approximately 25,000 acres in the Tuscaloosa Marine Shale ("TMS"), a shale play in central Louisiana and Mississippi. The TMS is an oil focused play and we intend to watch the play develop before we commit to drilling any exploratory wells. We do, however, plan to participate in outside operated wells with a small working interest prior to initiating an operated, high interest drilling program.

Jim Hogg County, Texas

We have entered into a letter agreement with a large south Texas mineral owner outlining the general terms and conditions of an exploration program involving acreage in Jim Hogg County, Texas. As of August 24, 2012, we had paid approximately $1.2 million into this exploration program.

Discontinued Operations

Joint Venture Assets

In October 2009, the Company entered into a joint venture with Patara Oil & Gas LLC ("Patara") 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. On May 13, 2011, the Company sold to Patara its 90% interest and 5% overriding royalty interest in the 21 wells drilled under this joint venture 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 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.

Rexer Assets

On May 13, 2011, the Company sold to Patara 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 was 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.

The remaining 25% working interest in Rexer-Tusa #2 was sold to Patara in October 2011 for $10,000. Rexer-Tusa #2 was a wildcat exploration well that was spud in May 2011. This well had no proved reserves at the time of sale. The Company has accounted for the sale of Rexer #1 and Rexer-Tusa #2 as discontinued operations as of December 31, 2011 and has included the results of these operations in discontinued operations for all periods presented.

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 675,000 acres from the Tetlin Village Council, the council formed by the governing body for the Native Village of Tetlin, an Alaska Native Tribe, as well as additional acres in unpatented Federal and State of Alaska mining claims for the exploration of gold deposits and associated minerals and rare earth elements (collectively, 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 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, 2012 were Shell Trading US Company (25%), NJR Energy Services (13%), ConocoPhillips Company (22%), Exxon Mobil Oil Corporation (11%), Enterprise Products Operating LLC (14%), and TransLouisiana Gas Pipeline Inc. (8%). 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.

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 and highlighted the dangers associated with exploration and production activities.

The legislative and regulatory response to the Deepwater Horizon Incident is ongoing. In 2010, the US Department of the Interior issued new rules designed to improve drilling and workplace safety, and various Congressional committees began pursuing legislation to greater regulate drilling activities and increase liability. In January 2011, the President's National Commission on the Deepwater Horizon Oil Spill and Offshore Drilling released its report, recommending that the federal government require additional regulation and an increase in liability caps.

Additional regulatory review, slower permitting processes and increased oversight have resulted in longer development cycle time for our Gulf of Mexico projects. Cycle time is the length of time it takes for a project to progress from developing a prospect to beginning production, and longer development cycle times could result in lower rates of return on our investments.

Increased regulation impacting our activities in the Gulf of Mexico could result in extensive efforts to ensure compliance and incremental compliance costs. A significant delay or cancellation of our planned Gulf of Mexico exploratory activities will reduce our longer term ability to replace reserves, resulting in a negative impact on production over time. To the extent current exploration activities are significantly delayed, a gap could occur in our long-term production profile with a negative impact on our operating results and cash flows.

Additional legislation or regulation is being discussed which could require each company doing business in the Gulf of Mexico to establish and maintain a higher level of financial responsibility under its Certificate of Financial Responsibility ("COFR"), a certificate required under the Oil Pollution Act of 1990 which evidences a company's financial ability to pay for cleanup and damages caused by oil spills. There have also been discussions regarding the establishment of a new industry mutual fund in which companies would be required to participate and which would be available to pay for consequential damages arising from an oil spill. These and/or other legislative or regulatory changes could require us to maintain a certain level of financial strength and may reduce our financial flexibility.

Future legislation or regulation is also likely to result in substantial increases in civil or criminal fines or sanctions. Such fines or sanctions could well exceed the actual cost of containment and cleanup associated with a well incident or spill. We are monitoring legislative and regulatory developments; however, the full legislative and regulatory response to the Deepwater Horizon Incident is not yet fully known.

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 BOEM administers the natural gas and oil leases held by the Company on federal onshore lands and offshore tracts in the Outer Continental Shelf. The BOEM 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 BOEM 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 BOEM 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.

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 BOEM. Our response team is trained annually and is tested through annual spill drills given by the BOEM. 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. The Company has developed and implemented a Safety and Environmental Management System ("SEMS") to address oil and gas operations in the Outer Continental Shelf ("OCS"), as required by the BSEE. Full implementation of the following thirteen mandatory elements of the American Petroleum Institute's Recommended Practice 75 (API RP 75) was required 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 identifies, addresses, and manages safety, environmental hazards, and its impacts during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. The Company has established goals, performance measures, training, accountability for its implementation, and provides necessary resources for an effective SEMS, as well as reviews 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 BSEE 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 of an audit may force us to shut-in our Gulf of Mexico operations.

Employees

We have ten employees, all of whom are full time. The Company outsources its human resources function to Insperity, Inc. 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 currently 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	67	Chairman and Director
Brad Juneau	52	President, Acting Chief Executive Officer and Director
Sergio Castro	43	Vice President, Chief Financial Officer, Treasurer and Secretary
Yaroslava Makalskaya	43	Vice President, Controller and Chief Accounting Officer
Marc L. Duncan	59	Vice Chairman of Operating Committee; Safety, Environmental and Regulatory Compliance Officer (SEARCO)
Charles A. Cambron	45	Vice President - Drilling
Michael J. Autin	53	Vice President - Production
B.A. Berilgen	64	Director
Jay D. Brehmer	47	Director
Charles M. Reimer	67	Director
Steven L. Schoonover	67	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. In August 2012, Mr. Peak received a medical leave of absence from the Company for up to six months and Mr. Juneau was elected President and Acting Chief Executive Officer. 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, and Contango ORE, Inc., an exploration stage company involved in the exploration of gold and associated minerals and rare earth elements in the state of Alaska.

Brad Juneau. Mr. Juneau was elected a director of Contango in April 2012 and President and Acting Chief Executive Officer in August 2012. Mr. Juneau is the sole manager of the general partner of JEX, a company involved in the generation of natural gas and oil prospects. Prior to forming Juneau Exploration in 1998, Mr. Juneau served as senior vice president of exploration for Zilkha Energy Company from 1987 to 1998. Prior to joining Zilkha Energy Company, Mr. Juneau served as staff petroleum engineer with Texas International Company for three years, where his principal responsibilities included reservoir engineering, as well as acquisitions and evaluations. Prior to that, he was a production engineer with Enserch Corporation in Oklahoma City. Mr. Juneau holds a BS degree in petroleum engineering from Louisiana State University. Mr. Juneau was also elected President, Acting Chief Executive Officer and director of Contango ORE, Inc. in August 2012.

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. Ms. Makalskaya has approximately 20 years of experience in accounting and finance, including 13 years in public accounting. Prior to joining Contango, Ms. Makalskaya was a director in 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 practices 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.

Marc L. 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") and Vice Chairman of the Operating Committee. Mr. Duncan has over 38 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.

Charles A. Cambron. Mr. Cambron joined Contango in August 2010 as Vice President of Drilling. 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.

Michael J. Autin. Mr. Autin joined Contango in May 2012 as Vice President of Production in August 2012. Mr. Autin has over 33 years of experience in the petroleum industry including the Gulf of Mexico and U.S onshore shale. He has held various positions including Production Manager, HSE Manager and Offshore Installation Manager. Prior to joining Contango, Mr. Autin was employed by BHP Billiton since October 2000, where most recently he was Gulf of Mexico Operations Manager, Field Manager and Operations Advisor. Mr. Autin attended Nicholls State University where he studied petroleum, safety and business. He received a BS degree in 1986.

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 BS in Petroleum Engineering in 1970 and a MS 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. Beginning December 1, 2011, each non-employee director of the Company received a quarterly retainer of $28,000 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. 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.

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, which was updated and adopted by the Company's Board of Directors in May 2012. 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

You may read and copy all or any portion of this annual report on Form 10-K, our quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, without charge at the office of the Securities and Exchange Commission (the "SEC") in Public Reference Room, 100 F Street NE, Washington, DC, 20549. Information regarding the operation of the public reference rooms may be obtained by calling the SEC at 1-800-SEC-0330. In addition, filings made with the SEC electronically are publicly available through the SEC's website at http://www.sec.gov, and at our website at http://www.contango.com. This annual report on Form 10-K, including all exhibits and amendments, has been filed electronically with the SEC.

Item 2. ***Properties***

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,		
	2012	2011	2010
		(thousands)	
Property acquisition costs:			
Unproved	$ 5,404	$ 2,802	$ 11,319
Proved	381	10,135	2,009
Exploration costs	1,154	14,016	52,805
Development costs	10,350	39,211	40,902
Total costs	$17,289	$ 66,164	$107,035

Drilling Activity

The following table shows our exploratory and developmental drilling activity for the periods indicated. The Company did not drill any wells during the fiscal year ended June 30, 2012. 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,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	—	—	—	—	1	1.0
Productive (offshore)	—	—	1	1.0	1	1.0
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	1	1.0	2	2.0
Total	—	—	2	2.0	4	4.0

	Year Ended June 30,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Developmental Wells:						
Productive (onshore)	—	—	9	7.5	13	13.0
Productive (offshore)	—	—	—	—	1	0.3
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	—	—	9	7.5	14	13.3

For the fiscal year ended June 30, 2011, of the nine productive onshore development 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, the one productive onshore exploratory well relates to our Rexer #1 well and the 13 productive onshore development wells relate to our Conterra Company wells. The Rexer #1 well and Conterra Company wells were sold on May 13, 2011 while the sale of the Rexer-Tusa #2 was completed in October 2011. These wells are classified as discontinued operations in our financial statements for all periods presented.

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, 2012:

	Developed Acreage (1)(2)		Undeveloped Acreage (1)(3)	
	Gross (4)	Net (5)	Gross (4)	Net (5)
Onshore (TMS)	—	—	13,848	13,848
Offshore Gulf of Mexico	21,949	13,242	26,283	22,653
Total	21,949	13,242	40,131	36,501

(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 1,788 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, 2012:

	Total Productive Wells (1)	
	Gross (2)	Net (3)
Natural gas (onshore)	—	—
Natural gas (offshore)	13	6.6
Oil	—	—
Total	13	6.6

(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, 2012, 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 members of the Company's management meet regularly with our independent third-party engineer to review these reserve estimates. Mr. Kenneth R. Peak, the Company's Chief Executive Officer, has primary responsibility for the preparation of the reserve report. Mr. Peak has been in the energy industry for 40 years, but also relies on others with technical backgrounds in a collaborative effort, all of who provide input to the independent third-party engineer. Mr. Brad Juneau, the Company's director, monitors production and pressure data daily and provides the majority of the input. Mr. Juneau holds a BS degree in petroleum engineering from Louisiana State University. Mr. Juneau has over 30 years of experience in the oil and gas industry and was a former registered petroleum engineer in the State of Texas. Other executives in accounting and production have advanced degrees and specialty licenses and also provide input to the independent third-party engineer and assist in reviewing the report.

The qualifications of the technical person at Cobb responsible for overseeing the preparation of our reserve estimates are set forth below.

- 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.

The following table sets forth our offshore proved reserves as of June 30, 2012:

	Developed	Undeveloped	Total
Natural gas (MMcf)	196,268	5,111	201,379
Oil and condensate (MBbls)	3,353	(41)	3,312
Natural gas liquids (MBbls)	5,664	222	5,886
Total proved reserves (MMcfe)	250,370	6,197	256,567
Pre-tax net present value, discounted at 10% (in thousands)	$686,900	$ 43,322	$730,222

Prior Year Reserves

Our estimated net proved natural gas, oil and natural gas liquids reserves as of June 30, 2009, 2010, 2011 and 2012 are disclosed on page F-24 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 had over 23 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. As of June 30, 2012, the Company had approximately 6.2 Bcfe of PUDs related to Mary Rose #6, a rate acceleration well on state of Louisiana acreage. Our plan is to develop our PUD reserves prior to December 31, 2016, which is five years from the initial date of disclosure of these PUD reserves.

As of June 30, 2011, the Company had approximately 39 Bcfe of PUDs. Of this amount, approximately 37.5 Bcfes were attributable to our discovery at Vermilion 170. We announced this discovery in March 2011, but as of June 2011, major completion and facility expenditures were still required to place this well on production. We therefore classified the reserves as PUD as of June 30, 2011. In September 2011, when the expenditures were completed and the well began production, we reclassified a portion of the reserves (11 Bcfe) to proved developed. At the time, we believed this was a water-drive well and that a second well would be required to access the remaining 26.5 Bcfe. As we obtained more data, we discovered that this was not the case and that the existing well would access all of the reserves. As a result of this information, we reclassified the remaining Vermilion 170 PUD reserves to proved developed in December 2011.

Of the 39 Bcfe of PUDs as of June 30, 2011, approximately 1.5 Bcfe were attributable to reserves in a different zone in our existing Eloise North well. In October 2011, the Company commenced workover operations to plug the Eloise North well in the Rob-L sands, and recomplete up-hole in the Cib-Op sands. As a result, in December 2011 we reclassified these PUD reserves to proved developed.

At June 30, 2010 the Company had approximately 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.

Modernization of Oil and Gas Reporting

Effective June 30, 2010, we implemented the SEC's final rules related to the modernization of oil and gas reporting (SEC's reserves rules). Although the SEC's reserves rules allow probable and possible reserves to be disclosed separately, we have elected not to disclose probable and possible reserves in this report. See Item 8. Financial Statements and Supplementary Data – Supplemental Oil and Gas Information (Unaudited) for a description of the most significant revisions to oil and gas reporting disclosures. The SEC's reserve rules 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.

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, 2012 was based on $3.13 per million British thermal units ("MMbtu") for natural gas at the NYMEX, $96.07 per barrel of oil at the West Texas Intermediate Posting, and $59.39 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, 2012 is as follows (in thousands):

	June 30, 2012
Pre-tax net present value, discounted at 10%	$ 730,222
Future income taxes, discounted at 10%	(216,290)
Standardized measure of discounted future net cash flows	$ 513,932

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.

PART II

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 onshore and offshore in the Gulf of Mexico in water-depths of less than 300 feet. COI, our wholly-owned subsidiary, acts as operator on certain offshore properties.

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.

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. The Company did not drill any wells during the fiscal year ended June 30, 2012, and as a result was not able to replace any reserves. Our permits to spud Ship Shoal 134 ("Eagle") and South Timbalier 75 ("Fang") were approved in September 2011 and March 2012, respectively, but a lack of rig availability prevented us from drilling these wells during fiscal year 2012. While waiting for drilling rigs to become available, we spent most of fiscal year 2012 generating new prospects. On June 20, 2012, the Company was the apparent high bidder on six lease blocks at the Central Gulf of Mexico Lease Sale 216/222. Upon approval from the BSEE, our plan is to promptly apply for permits to drill these prospects in 2013, 2014 and 2015. We therefore do not believe there will be a material impact on future sales or revenues or income from continuing operations.

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.

Related Party Transactions. The Company relies on JEX and REX to generate its offshore and onshore domestic natural gas and oil prospects. In addition to generating new prospects, JEX occasionally evaluates offshore and onshore exploration prospects generated by third-party independent companies for us to purchase. See Note 13 - Related Party Transactions for a detailed description of our transactions with JEX and REX.

See "Risk Factors" on page 13 of the Original Filing 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 table shows the relationship between volumes and revenues from continuing operations.

	Fiscal Year Ended June 30,			
	2012		2011	
	(thousands, except percentage)			
Natural gas volumes (Mcf)	23,617	75.50%	24,268	75.48%
Condensate and NGL volumes (Mcfe)	7,662	24.50%	7,885	24.52%
Total volumes	31,279		32,153	
Natural gas revenues	$ 73,232	40.85%	$106,781	52.93%
Condensate and NGL revenues	106,040	59.15%	94,940	47.07%
Total revenues	$179,272		$201,721	

The table below sets forth average daily production data in Mmcfed from our offshore wells for the three months ended for each of the periods presented:

	September 30, 2011	December 31, 2011	March 31, 2012	June 30, 2012
Dutch and Mary Rose wells	63.2	66.2	59.3	67.5
Ship Shoal 263 well (Nautilus)	7.6	10.9	7.8	7.6
Vermilion 170 well (Swimmy)	2.3	17.2	15.3	15.5
Non-operated wells	0.3	0.2	0.3	0.2
	73.4	94.5	82.7	90.8

Dutch and Mary Rose Wells. Third-party platform and pipeline repairs, as well as third-party gas processing plant shut-ins reduced our flowrates at our Dutch #1, #2, and #3 wells during the three months ended September 2011. During the three months ended March 31, 2012 our Dutch #1, #2 and #3 wells were shut in for a total of 10 days for maintenance and to repair a small pipeline leak. As of August 24, 2012, these ten wells were flowing approximately 67.1 Mmcfed, net to Contango.

Ship Shoal 263 Well (Nautilus). For the three months ended September 30, 2011, production at Ship Shoal 263 was temporarily shut-in due to a leak on a third-party owned and operated pipeline. For the three months ended March 31, 2012 and June 30, 2012, production was intermittent due to overheating and scaling problems. As of August 24, 2012, the well was flowing at approximately 3.0 Mmcfed, net to Contango.

Vermilion 170 Well (Swimmy). Our Vermilion 170 well began production in September 2011, and as of August 24, 2012, was flowing at approximately 13.4 Mmcfed, net to Contango.

The table below sets forth revenue, production data, average sales prices and average production costs associated with our sales of natural gas, oil and natural gas liquids (“NGLs”) from continuing operations for the fiscal years ended June 30, 2012, 2011 and 2010. 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, (thousands)			Year ended June 30, (thousands)		
	2012	2011	%	2011	2010	%
Revenues:						
Natural gas and oil sales.	$179,272	$201,721	-11%	$201,721	$159,010	27%
Total revenues	$179,272	$201,721		$201,721	$159,010	
Annual Production:						
Natural gas (million cubic feet)						
Dutch and Mary Rose field	18,303	20,589	-11%	20,589	21,019	-2%
Vermilion 170 field	3,098	—	100%	—	—	0%
Other fields	2,216	3,679	-40%	3,679	62	5834%
Total natural gas	23,617	24,268	-3%	24,268	21,081	15%
Oil and condensate (thousand barrels)						
Dutch and Mary Rose field	347	456	-24%	456	501	-9%
Vermilion 170 field	123	—	100%	—	—	0%
Other fields	145	217	-33%	217	3	7133%
Total oil and condensate.	615	673	-9%	673	504	34%
Natural gas liquids (thousand gallons)						
Dutch and Mary Rose field	21,452	25,389	-16%	25,389	24,642	3%
Vermilion 170 field	5,390	—	100%	—	—	0%
Other fields	959	1,537	-38%	1,537	48	3102%
Total natural gas liquids.	27,801	26,926	3%	26,926	24,690	9%
Total (million cubic feet equivalent)						
Dutch and Mary Rose field	23,450	26,952	-13%	26,952	27,545	-2%
Vermilion 170 field	4,606	—	100%	—	—	0%
Other fields	3,223	5,201	-38%	5,201	87	5888%
Total natural gas liquids.	31,279	32,153	-3%	32,153	27,632	16%
Daily Production:						
Natural gas (million cubic feet per day)						
Dutch and Mary Rose field	50.0	56.4	-11%	56.4	57.6	-2%
Vermilion 170 field	8.5	—	100%	—	—	0%
Other fields	6.1	10.1	-40%	10.1	0.2	5834%
Total natural gas	64.5	66.5	-3%	66.5	57.8	15%
Oil and condensate (thousand barrels per day)						
Dutch and Mary Rose field	0.9	1.2	-24%	1.2	1.4	-9%
Vermilion 170 field	0.3	—	100%	—	—	0%
Other fields	0.4	0.6	-33%	0.6	0.0	7133%
Total oil and condensate.	1.7	1.8	-9%	1.8	1.4	34%
Natural gas liquids (thousand gallons per day)						
Dutch and Mary Rose field	58.6	69.6	-16%	69.6	67.5	3%
Vermilion 170 field	14.7	—	100%	—	—	0%
Other fields	2.6	4.2	-38%	4.2	0.1	3102%
Total natural gas liquids.	76.0	73.8	3%	73.8	67.6	9%
Total (million cubic feet equivalent per day)						
Dutch and Mary Rose field	64.1	73.8	-13%	73.8	75.5	-2%
Vermilion 170 field	12.6	—	100%	—	—	0%
Other fields	8.8	14.2	-38%	14.2	0.2	5888%
Total natural gas liquids.	85.5	88.1	-3%	88.1	75.7	16%
Average Sales Price:						
Natural gas (per thousand cubic feet).	$ 3.10	$ 4.40	-30%	$ 4.40	$ 4.48	-2%
Oil and condensate (per barrel)	$ 112.75	$ 91.98	23%	$ 91.98	$ 77.18	19%
Natural gas liquids (per gallon)	$ 1.32	$ 1.23	7%	$ 1.23	$ 1.04	18%
Total (per thousand cubic feet equivalent)	$ 5.73	$ 6.27	9%	$ 6.27	5.75	9%
Operating expenses	$ 25,183	$ 25,691	-2%	$ 25,691	$ 16,692	54%
Exploration expenses	$ 346	$ 9,751	-96%	$ 9,751	$ 20,850	-53%
Depreciation, depletion and amortization.	$ 49,052	$ 52,198	-6%	$ 52,198	$ 34,521	51%
Impairment of natural gas and oil properties	$ —	$ 1,786	-100%	$ 1,786	$ 952	88%
General and administrative expenses	$ 10,418	$ 12,341	-16%	$ 12,341	$ 4,599	168%
Other income (expense).	$ (312)	$ (157)	99%	$ (157)	$ 511	-131%

Loss from affiliates (net of tax of $241)	$	(449)	$	—	100%	$	—	$	—	0%
Selected data per Mcfe:										
Total lease operating expenses.	$	0.81	$	0.80	1%	$	0.80	$	0.60	33%
General and administrative expenses	$	0.33	$	0.38	-13%	$	0.38	$	0.17	124%
Depreciation, depletion and amortization of natural gas and oil properties.	$	1.54	$	1.61	-4%	$	1.61	$	1.24	30%

Not included in the table above is production information from our discontinued operations. For the fiscal year ended June 30, 2012, our discontinued operations produced approximately 1.7 Mmcf of natural gas at an average price of $3.79 per Mcf. For the fiscal year ended June 30, 2011, our discontinued operations produced approximately 1,892 Mmcf of natural gas, 12.8 MBbls of condensate, and 2.6 million gallons of natural gas liquids at an average price of $3.45 per Mcf, $86.91 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.

Natural Gas, Oil and NGL Sales. All of our revenues are from the sale of our natural gas, oil and natural gas liquids 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.

We reported revenues of approximately $29.8 million for the year ended June 30, 2012, compared to revenues of approximately $201.7 million for the year ended June 30, 2011. This decrease in sales was principally attributable to lower equivalent production for the period (discussed below) as well as a lower average equivalent sales price received for the period.

We reported revenues of approximately $201.7 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, oil and NGL production for the period (discussed below) as well as higher oil and NGL prices for the period, slightly offset by lower natural gas prices.

Average Sales Prices. For the year ended June 30, 2012, the price of natural gas was $3.10 per Mcf while the price for oil and NGLs was $112.75 per barrel and $1.32 per gallon, respectively. For the year ended June 30, 2011, the price of natural gas was $4.40 per Mcf while the price for oil and NGLs was $91.98 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.

Natural Gas, Oil and NGL Production. Our net natural gas production for the year ended June 30, 2012 was approximately 64.5 Mmcfd, down from approximately 66.5 Mmcfd for the year ended June 30, 2011. Net oil and condensate production for the comparable periods also decreased from approximately 1,800 barrels per day to approximately 1,700 barrels per day, and our NGL production increased from approximately 73,800 gallons per day to approximately 76,000 gallons per day. In total, equivalent production decreased from 88.1 Mmcfed to 85.5 Mmcfed, principally attributable to our Eloise North well which stopped producing in October 2011 and was subsequently recompleted as our Mary Rose #5 well in January 2012. Since recompletion, this well has only produced intermittently. Partially offsetting this decrease in production is our Vermilion 170 well which began producing in fiscal year 2012.

Our net natural gas production for the year ended June 30, 2011 was approximately 66.5 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 barrels per day to 1,800 barrels per day, while NGL production increased from approximately 67,600 gallons per day to 73,800 gallons per day. In total, equivalent production increased from 75.7 Mmcfed to 88.1 Mmcfed. This increase in natural gas, oil and NGL production was principally attributable to our Ship Shoal 263 well which began producing in June 2010 and our Eloise South well (now our Dutch #5 well) which began producing in July 2010. Also contributing to the increase in production was increased production from our four Mary Rose wells, Dutch #4 and our Eloise North well (now our Mary Rose #5 well), which had been shut-in for approximately 35 days during fiscal year 2010 due to our ruptured 20” pipeline. This increase in production was partially offset by temporarily shutting in our Eloise South well in October 2010 and our Eloise North well in February 2011 for remedial work.

Operating Expenses. Operating expenses for the year ended June 30, 2012 were approximately $6.5 million, which included approximately $4.1 million in Louisiana state severance taxes, $1.6 million in workover costs, and $4.4 million of well insurance. The remaining $15.1 million related to lease operating expenses for 12 offshore wells. Operating expenses for the year ended June 30, 2011 were approximately $5.9 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 $14.8 million related to lease operating expenses for 11 offshore wells. Operating expenses for the year ended June 30, 2010 were approximately $16.7 million, which included approximately $5.3 million of Louisiana state severance taxes, $0.7 million in workover costs and $10.7 million related to lease operating expenses for nine offshore wells.

Exploration Expenses. We reported approximately $45.0 million of exploration expenses for the year ended June 30, 2012, related to various geological and geophysical activities, seismic data and delay rentals.

We reported approximately $0.0 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.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization for the year ended June 30, 2012 was approximately $9.6 million. This compares to approximately $11.0 million for the year ended June 30, 2011. The decrease in depreciation, depletion and amortization was primarily attributable to an overall decrease in production due to our Eloise North well which stopped producing in October 2011 and was subsequently recompleted as our Mary Rose #5 well in

January 2012. Since recompletion, this well has only produced intermittently. Partially offsetting this decreased production is our Vermilion 170 well which began producing in fiscal year 2012.

Depreciation, depletion and amortization for the year ended June 30, 2011 was approximately $11.0 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 and Eloise South 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 had been 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 temporarily shutting in our Eloise South well in October 2010 and our Eloise North well in February 2011 for remedial work.

Impairment of Natural Gas and Oil Properties. No impairment expense was recorded for the year ended June 30, 2012. 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.

General and Administrative Expenses. General and administrative expenses for the year ended June 30, 2012 were approximately $2.6 million, compared to approximately $2.2 million for the year ended June 30, 2011. Major components of general and administrative expenses for the year ended June 30, 2012 included approximately $6.6 million in salaries, bonuses, stock-based compensation, benefits and board compensation, $0.4 million in insurance costs, $0.7 million in accounting and tax services, $0.9 million in legal and consulting expenses, $0.7 million in franchise taxes, and $1.1 million in office administration and other expenses.

General and administrative expenses for the year ended June 30, 2011 were approximately $2.2 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. 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.

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 0%, 5% and 1% of combined revenues for the fiscal year ended June 30, 2012, 2011 and 2010, respectively. See Note 5 – 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 $17.9 million in cash for the year ended June 30, 2012 compared to $12.6 million for the same period in 2011. This decrease in cash provided by operating activities was primarily attributable to decreased natural gas, oil and NGL sales and production as well as higher amounts of taxes paid due to reduced drilling activities in 2012.

Cash flow from operating activities provided approximately $12.6 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 wells, as well as from other wells which were shut-in for approximately 35 days in fiscal year 2010.

Cash From Investing Activities. Cash used in investing activities for the year ended June 30, 2012 was approximately $10.1 million, compared to $33.3 million used in investing activities for the year ended June 30, 2011. The higher level of cash used in investing activities in 2012 was primarily attributable to investing approximately $0.7 million in affiliates, partially offset by a decrease in capital expenditures for drilling exploration and development wells.

Cash 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 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 From Financing Activities. Cash used in financing activities for the year ended June 30, 2012 were approximately $0.0 million, compared to $9.8 million used in financing activities for the same period in 2011. During the fiscal year ended June 30, 2012, the Company invested significantly more to repurchase shares of its common stock pursuant to its share repurchase program.

Cash 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.

Income Taxes. During the year ended June 30, 2012, 2011 and 2010, we paid approximately $0.6 million, $31.9 million, and $11.5 million, respectively, in federal and state income taxes, net of refunds received.

Capital Budget. For the remainder of fiscal year 2013, our capital expenditure budget calls for us to invest approximately $146.7 million from cash flow from operations and cash on hand as follows:

- We have budgeted to invest approximately $25.0 million to drill our Ship Shoal 134 (“Eagle”) prospect.
- We have budgeted to invest approximately $28.0 million to drill our South Timbalier 75 (“Fang”) prospect.
- We have budgeted to invest approximately $7.2 million to complete laying flowlines and installing compression at our Eugene Island 11 and Vermilion 170 platforms.
- We have budgeted to invest approximately $7.6 million for remaining leasehold costs and rental payments for the six blocks we bid on at the Central Gulf of Mexico Lease Sale 216/222.
- We have budgeted to invest approximately $30 million to drill two wildcat exploration wells in the Gulf of Mexico.
- We have budgeted to invest approximately $41.2 million in Exaro Energy III LLC (remaining balance of $82.5 million commitment).
- We have budgeted to invest approximately $7.7 million in Alta Energy (remaining balance of $20 million commitment).

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, 2012, we had approximately $124.7 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 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-23 through F-26 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 2012, 2011 and 2010, the Company realized approximately $(0.4) million, $6.7 million and $0.4 million in operating cash flows from discontinued operations, approximately $10,000, $10.9 million and $(25.2) million in investing cash flows from discontinued operations and approximately $0.4 million, $(17.5) million and $24.8 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, 2012:

	Payment due by period (thousands)				
	Total	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Long term debt	$ —	$ —	$ —	$ —	$ —
Delay rentals	383	122	221	40	—
Asset retirement obligations	21,400	—	—	—	21,400
Operating leases	876	248	502	126	—
Total	$22,659	$ 370	$ 723	$ 166	$ 21,400

In addition, the Company pays a commitment fee of 0.125% on the unused borrowing capacity of our $40 million credit facility with Amegy Bank (See "Credit Facility" below). We have also committed to invest up to an additional $41.2 million in Exaro Energy, an additional $8.4 million ($7.7 million as of August 24) in Alta Energy, and an additional $8.8 million ($7.6 million as of August 24) for remaining leasehold costs and rental payments for the six blocks we bid on at the Central Gulf of Mexico Lease Sale 216/222.

Credit Facility

On October 22, 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the "Credit Agreement"). The Credit Agreement currently has a $40 million hydrocarbon borrowing base available to fund the Company's exploration and development activities, as well as repurchase 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, including our natural gas and oil properties. 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 effective November 1, 2011, a commitment fee of 0.125% is owed 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, 2012 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $2.5 million, $5.3 million, and $8.5 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 December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-11 *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11). ASU 2011-11 requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. ASU 2011-11 is effective for annual and interim periods beginning on or after January 1, 2013. We are currently evaluating the provisions of ASU 2011-11 and assessing the impact, if any, it may have on the disclosures in our financial statements.

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 the Original Filing. 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 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., 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)
10.46	First Amended and Restated Limited Liability Company Agreement dated as of March 31, 2012. (23)
10.47	Advisory Agreement between Contango Oil & Gas Company and Juneau Exploration, L.P., dated as of April 5, 2012. (24)
10.48†	Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of October 9, 2008 between Contango Offshore Exploration LLC and Contango Operators, Inc.
10.49†	Amendment to Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of October 7, 2009 between Contango Offshore Exploration LLC and Contango Operators, Inc.
10.50†	Amendment to Participation Agreement covering OCS-G 27927, Ship Shoal Block 263, South Addition, dated as of January 29, 2010 between Contango Offshore Exploration LLC and Contango Operators, Inc.
10.51†	Participation Agreement covering OCS-G 33596, Vermilion 170, dated as of July 1, 2010 between Republic Exploration LLC and Contango Operators, Inc.
10.52†	Participation Agreement covering OCS-G 33640, Ship Shoal 121; OCS-G 33641, Ship Shoal 122; and OCS-G 22701, Ship Shoal 134, dated as of July 1, 2010 between Republic Exploration LLC and Contango Operators, Inc.
10.53†	Amendment to Participation Agreement covering OCS-G 33640, Ship Shoal 121; OCS-G 33641, Ship Shoal 122; and OCS-G 22701, Ship Shoal 134, dated as of June 30, 2012 between Republic Exploration LLC and Contango Operators, Inc.
10.54†	Participation Agreement covering OCS-G 22738, South Timbalier 75, dated as of July 26, 2011 between Republic Exploration LLC and Contango Operators, Inc.
10.55†	Amendment to Participation Agreement covering OCS-G 22738, South Timbalier 75, dated as of August 21, 2012 between Republic Exploration LLC and Contango Operators, Inc.
10.56†	Participation Agreement covering Tuscaloosa Marine Shale, dated as of August 27, 2012 between Juneau Exploration LP and Contango Operators, Inc.
10.57†	Letter Agreement dated as of June 8, 2012 between Juneau Exploration LP and Contango Operators, Inc.
10.58†	Participation Agreement covering Central Gulf of Mexico Lease Sale 216/222, dated as of August 27, 2012 between Republic Exploration LLC and Contango Operators, Inc.
10.59†	Participation Agreement covering Central Gulf of Mexico Lease Sale 216/222, dated as of August 27, 2012 between Juneau Exploration LP and Contango Operators, Inc.
10.60†	Agreement to Purchase Overriding Royalty Interest, dated March 1, 2010 between Contango Offshore Exploration LLC and Juneau Exploration LP.
14.1†	Code of Ethics.
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 Acting 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 Acting 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.

† Previously submitted with the Original Filing.
* Indicates a management contract or compensatory plan or arrangement.
** Filed herewith.

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.
23. Filed as an exhibit to the Company's report on Form 8-K, dated as of March 31, 2012, as filed with the Securities and Exchange Commission on April 5, 2012.
24. Filed as an exhibit to the Company's report on Form 8-K, dated as of April 10, 2012, as filed with the Securities and Exchange Commission on April 11, 2012.

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

Date: , 2013	D-R-A-F-T
	Joseph J. Romano Chief Executive Officer (principal executive officer)

INDEX OF EXHIBITS

Number	Description
31.1	Certification of the Chief Executive Officer of Contango Oil & Gas Company required by Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended.
31.2	Certification of the Chief Financial Officer of Contango Oil & Gas Company required by Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended.
99.1	Report of William M. Cobb & Associates, Inc.

Exhibit 31.1

CERTIFICATION REQUIRED BY RULE 13a-14(a) OF THE SECURITIES EXCHANGE ACT OF 1934

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Joseph J. Romano, certify that:

1. I have reviewed this annual report on Form 10-K/A of Contango Oil & Gas Company; and
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.

Date: July [-], 2013

D-R-A-F-T

Joseph J. Romano
Chief Executive Officer

Exhibit 31.2

**CERTIFICATION REQUIRED BY RULE 13a-14(a) OF
THE SECURITIES EXCHANGE ACT OF 1934**

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Sergio Castro, certify that:

1. I have reviewed this annual report on Form 10-K/A of Contango Oil & Gas Company; and

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.

Date: July [-], 2013

D-R-A-F-T
Sergio Castro
Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.1

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

12770 Coit Road, Suite 907
Dallas, Texas

(972) 385-0354
Fax: (972) 788-5165
E-Mail: office@wmcobb.com

July [___], 2013

Mr. Joseph J. Romano
Contango Oil & Gas Company
3700 Buffalo Speedway, Suite 960
Houston, TX 77098

Dear Mr. Romano:

In accordance with your request, William M. Cobb & Associates, Inc. (Cobb & Associates) has estimated the proved reserves and future income as of July 1, 2012, 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. This report was initially completed on August 18, 2012 and is being amended on July 22, 2013.

Table 1 summarizes our estimate of the proved oil and gas reserves and their pre-federal income tax value undiscounted and discounted at ten 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 are not intended to necessarily represent an estimate of fair market value. These estimates were prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities – Oil and Gas.

TABLE 1

CONTANGO - NET RESERVES AND VALUE
AS OF JULY 1, 2012
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	145,100	4,170	2,799	851,035	607,101
Non-Producing	51,168	1,494	554	189,064	79,799
Undeveloped	5,111	222	-41	6,461	43,322
Total Proved	201,379	5,886	3,312	1,046,560	730,222

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July 24, 2013
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Total proved reserves expressed as MMCFE as of July 1, 2012 is 256,564,984. This amount is calculated using six MCF per barrel ratio applied to condensate and NGL volumes.

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^{o} Fahrenheit and the legal pressure base for the specific location of the gas reserves.

It should be recognized that different levels of risk and uncertainty are associated with different reserve categories; however, the reserves and revenues presented in this report have not been adjusted for risk.

Our report, which was filed with Contango's Form 10-K for the fiscal year ended June 30, 2012, covers 256,564,984 MMCFE, or 100 percent of the total reserves presented in Contango's Form 10-K. This amended report is being filed with Contango's form 10-K/A for the fiscal year ended June 30, 2012. We have used all assumptions, data, methods and procedures considered necessary and appropriate 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 four more wells, the Dutch 2, 3, 4 and 5, on Federal acreage. The Dutch 1, 2, and 3 wells produce to the Chevron Eugene Island 24 platform. The Dutch 4 and 5 well produce to the Contango 'H' platform.

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

Proved reserves for the Eugene Island 10 main 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 wells actually producing on July 1, 2012 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 June, 2013. Delivery pressures with compression will be lowered to 200 psi. Capital costs for installation of flow lines and compression are $5,297,000 for flow lines and $12,735,000 for compression. Fuel charges are calculated based on a volume of 2,000 MCFPD for each platform at the current gas price.

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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 ten percent (PV10), approximately 77 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.

Two wells on the State acreage originally produced from gas reservoirs separate from the main CibOp reservoir. The Eloise 3 well produced and depleted a lower RobL sand and was recompleted to an isolated CibOp sand during the last quarter of 2011. This stray CibOp producer, now called the Mary Rose 5, began producing in January 2012. The Eloise 5 well has also produced and depleted a lower RobL sand and was recompleted to the main CibOp reservoir mid-year 2011. The Eloise 5 was renamed the Dutch 5 well and began producing from the main CibOp reservoir in July 2011.

One future PUD well has been scheduled for the main CibOp reservoir. The Mary Rose 6 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 2009 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 7.6 BCF of gas and 507 MBBL condensate. The well is currently producing at a rate of about 4.3 MMCF per day with 300 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 13,800 feet. Production started in September 2011 upon installation of a production platform in 87 feet of water. Current production rates are 17.7 MMCFPD with 500 barrels of condensate. Cumulative production to date is approximately 5.3 BCF of gas and 187 MBBL condensate. Proved reserves are based on a reservoir simulation model history matched to actual production and pressure performance.

OIL AND GAS PRICING

Projections of proved reserves contained in this report utilize constant product prices of $3.13 per MMBTU of gas and $96.07 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 54.8 percent of the oil price for the wells producing to the Chevron platform and 52.2 percent for wells producing to the 'H' platform.

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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 gross 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 production handling at the EI-24 platform. Based on historical data provided by Contango, the transportation and processing fees are $0.066 per MCF of produced gas, $1.659 per barrel of oil, and $4.034 per barrel of NGL. Additionally, a fixed operating cost of $171,522 per month per well was scheduled. The gas shrinkage factor applied for the removal of NGL's from the gas stream was determined to be 0.8904 MCF of sales gas per MCF of produced gas.

For the Mary Rose 1 through 4 wells and the Dutch 4 and 5 wells, which produce to the Contango 'H' platform, a total fixed operating cost of $854,084 per month was scheduled along with certain transportation and processing fees. Transportation and processing fees of $1.082 per barrel of oil and $2.926 per barrel of NGL were scheduled. A gas processing fee of $0.045 per MCF was also scheduled. The gas shrinkage factor applied for the removal of NGL's from the gas stream was determined to be 0.8793 MCF of sales gas per MCF of produced gas.

For Ship Shoal 263, a fixed operating cost of $232,046 per month was scheduled based on historical data provided by Contango. Variable costs were also scheduled as follows: $0.041 per MCF of gas, $3.548 per barrel of oil, and $2.606 per barrel of NGL. NGL production is based on a projected yield of 9.712 BBL per MCF and the resulting gas shrinkage factor is 0.9671 MCF of sales gas per MCF of produced gas. NGL price is scheduled as 60.3 percent of the oil price.

For Vermilion 170, operating costs were determined using the available historical expense data from Contango. A fixed monthly operating cost of $129,875 was scheduled. Variable costs of $0.023 per MCF of gas, $3.246 per barrel of oil, and $0.856 per barrel of NGL were scheduled. NGL production is based on a projected yield of 34.912 BBL per MCF and the resulting gas shrinkage factor is 0.8492 MCF of sales gas per MCF of produced gas. NGL price is scheduled as 44.3 percent of the oil price.

OTHER

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

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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. Our estimates are based upon the assumption that the properties will be operated in a prudent manner and that no government regulations and controls will be instituted that would impact the ability of Contango to recover the reserves. 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 Cobb & Associates, nor has the actual degree of interest owned been independently confirmed. The data used in our evaluation were obtained from Contango and the nonconfidential files of Cobb & Associates 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

D-R-A-F-T
Frank J. Marek, P.E.
President

D-R-A-F-T
Andrea S. Mielcarek
Staff Engineer

FJM:ar
Attachments