CONTANGO OIL & GAS CO
Form 10-K
August 29, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended June 30, 2013

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

Commission file number 001-16317
CONTANGO OIL & GAS COMPANY
(Exact name of registrant as specified in its charter)

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

3700 Buffalo Speedway, Suite 960
Houston, Texas 77098
(Address of principal executive offices)
(713) 960-1901
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Common Stock, Par Value $0.04 per share	NYSE 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 [X]

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

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

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

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

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

At December 31, 2012, the aggregate market value of the registrant's common stock held by non-affiliates (based upon the closing sale price of shares of such common stock as reported on the NYSE MKT was $559,355,116. As of August 26, 2013, there were 15,194,952 shares of the registrant's common stock outstanding.

Documents Incorporated by Reference

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

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE FISCAL YEAR ENDED JUNE 30, 2013
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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

- Low and/or declining prices for natural gas and oil
- Natural gas and oil price volatility
- Operational constraints, start-up delays and production shut-ins at both operated and non-operated production platforms, pipelines and gas processing facilities
- The risks associated with acting as the operator in drilling deep high pressure and temperature wells in the Gulf of Mexico, including well blowouts and explosions
- The risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry holes, especially in prospects in which the Company has made a large capital commitment relative to the size of the Company’s capitalization structure
- The timing and successful drilling and completion of natural gas and oil wells
- Availability of capital and the ability to repay indebtedness when due
- Availability of rigs and other operating equipment
- Ability to receive Bureau of Safety and Environmental Enforcement permits on a time schedule that permits the Company to operate efficiently
- Ability to raise capital to fund capital expenditures
- Timely and full receipt of sale proceeds from the sale of our production
- The ability to find, acquire, market, develop and produce new natural gas and oil properties
- Interest rate volatility
- Zero or near-zero interest rates
- Uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures
- Operating hazards attendant to the natural gas and oil business
- Downhole drilling and completion risks that are generally not recoverable from third parties or insurance
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- Potential mechanical failure or under-performance of significant wells, production facilities, processing plants or pipeline mishaps
- Weather
- Availability and cost of material and equipment
- Delays in anticipated start-up dates
- Actions or inactions of third-party operators of our properties
- Actions or inactions of third-party operators of pipelines or processing facilities
- The ability to find and retain skilled personnel
- Strength and financial resources of competitors
- Federal and state regulatory developments and approvals
- Environmental risks
- Worldwide economic conditions
- The ability to construct and operate offshore infrastructure, including pipeline and production facilities
- The continued compliance by the Company with various pipeline and gas processing plant specifications for the gas and condensate produced by the Company
- Drilling and operating costs, production rates and ultimate reserve recoveries in our Eugene Island 10 (“Dutch”) and state of Louisiana (“Mary Rose”) acreage
- Restrictions on permitting activities
- Expanded rigorous monitoring and testing requirements
- Legislation that may regulate drilling activities and increase or remove liability caps for claims of damages from oil spills
- Ability to obtain insurance coverage on commercially reasonable terms
- Accidental spills, blowouts and pipeline ruptures
- Impact of new and potential legislative and regulatory changes on Gulf of Mexico operating and safety standards

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

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

PART I
Item 1. Business
Overview

Contango is a Houston, Texas based, independent natural gas and oil company. The Company's core business is to explore, develop, produce and acquire natural gas and oil properties offshore in the shallow waters of the Gulf of Mexico. Contango Operators, Inc. ("COI"), our wholly-owned subsidiary, acts as operator of our offshore properties. Contango has additional onshore investments in i) Alta Resources Investments, LLC ("Alta"), whose primary area of focus is the liquids-rich Kaybob Duvernay in Alberta, Canada; ii) Exaro Energy III LLC ("Exaro"), which is primarily focused on the development of proved natural gas reserves in the Jonah Field in Wyoming; and iii) the Tuscaloosa Marine Shale ("TMS") where we own approximately 24,000 acres.

On April 19, 2013, the Company's founder and former Chairman, President and Chief Executive Officer, Mr. Kenneth R. Peak, passed away at the age of 67. The Company held a $10 million life insurance policy for Mr. Peak and received the proceeds of such policy in early May 2013.

On April 30, 2013, the Company announced that it had signed a merger agreement (the "Merger Agreement") with Crimson Exploration Inc. ("Crimson"), for an all-stock transaction pursuant to which Crimson will become a wholly owned subsidiary of Contango (the "Merger"). Upon consummation of the Merger, each share of Crimson stock will be converted into 0.08288 shares of Contango stock resulting in Crimson stockholders owning 20.3% of the post-merger Contango. This transaction is subject to shareholder approval of both Contango and Crimson and is expected to close in October 2013, subject to satisfaction of a number of closing conditions.

Crimson is a Houston, Texas-based independent energy company engaged in the exploitation, exploration, development and acquisition of crude oil and natural gas, primarily in the onshore Gulf Coast regions of the United States. Crimson currently owns approximately 95,000 net acres onshore in Texas, Louisiana, Colorado and Mississippi. Crimson refers to its four corporate areas as (i) Southeast Texas, focusing on the Woodbine, Eagle Ford and Georgetown formations, (ii) South Texas, focusing on the Eagle Ford and Buda formations, (iii) East Texas, focusing on the Haynesville, Mid-Bossier and James Lime formations, and (iv) Rockies and Other, focusing on the Niobrara and D&J Sand formations. Crimson's strategy is to continue to increase crude oil and liquids-rich reserves and production from an extensive inventory of drilling prospects, de-risk unproved prospects in core operating areas, and opportunistically grow reserves through acquisitions complementary to its existing asset base.

As of June 30, 2013, Crimson had estimated proved reserves of 117.1 billion cubic feet equivalent ("Bcfe") of natural gas equivalents, based on SEC reporting guidelines. For the quarter ended June 30, 2013, Crimson's average production was approximately 44.2 million cubic feet equivalent per day ("Mmcfed"). Crimson's common stock is traded on the NASDAQ under the symbol "CXPO."

On August 5, 2013, the Company announced that Alta had agreed to sell its interest in over 67,000 acres in the Kaybob Duvernay in Alberta, Canada. Proceeds from the sale are expected to be approximately $29 million, net to the Company. The sale is expected to close by October 2013 after satisfaction of a number of closing conditions.

On July 30, 2013, we spud our South Timbalier 17 prospect with the Hercules 202 rig, and on August 22, 2013 we announced a successful well. Estimated costs net to Contango to drill, complete and bring this well to full production status are $12.5 million.

Our Strategy

Our exploration strategy is predicated upon the belief that the only competitive advantage in the commodity-based natural gas and oil business is to be among the lowest cost producers.

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

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 offshore prospects. Should we be successful in any of our

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offshore prospects, we will have the opportunity to spend significantly more capital to complete development and bring the discovery to producing status.

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.

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.

As of June 30, 2013, the Company's offshore production was approximately 64.6 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 three platforms:

Eugene Island 11 Platform

Our Company-owned and operated production platform at Eugene Island 11 was designed with a capacity of 500 million cubic feet per day ("Mmcfd") and 6,000 barrels of oil per day ("bopd"). In September 2010 the Company 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 Dutch wells in federal waters and five Mary Rose wells in state of Louisiana waters. From these platforms, 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.

Alternatively, gas can flow to the American Midstream pipeline via our 8" pipeline, which has been designed with a capacity of 80 Mmcfed, and from there to a third-party owned and operated on-shore processing facility at Burns Point, Louisiana. Condensate can also flow via an ExxonMobil pipeline to on-shore markets and multiple refineries. As of June 30, 2013, we were producing approximately 54.4 Mmcfed, net to Contango, from these platforms.

Based on current production and decline rates, the Company has determined the need to place its Mary Rose wells on compression in mid-2014, and place its Dutch wells on compression in late-2015. The Company is in the process of designing and building a large turbine type compressor for the platform at an estimated cost of $9.1 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, 2013, the Company had incurred approximately $8.3 million to design and build the compressor.

In late-2012, the Company suspended production to the Eugene Island 24 Platform, after installing auxiliary flowlines to enable the Company to redirect its Dutch #1, #2, and #3 wells to Eugene Island 11. In June 2013, the Company removed all remaining flowlines connected to the Eugene Island 24 Platform.

Ship Shoal 263 Platform

Our Company-owned and operated production 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 Ship Shoal 263 well, which flows via the Transcontinental Gas Pipeline to onshore processing plants. As of June 30, 2013, we were producing approximately 0.7 Mmcfed, net to Contango, from this platform. We believe this well may be fully depleted in the next twelve months. The well reached payout during fiscal year 2012. We will continue producing this well as long as it is economical.

In March 2013, due to the decline in production and high water levels from our Ship Shoal 263 well, our reservoir engineer revised his estimated net proved natural gas and oil reserves from this well. As a result, the net book value of our Ship

Shoal 263 well exceeded the future undiscounted cash flows associated with its reserves. Accordingly, the Company recognized an impairment expense of approximately $12.0 million for the fiscal year ended June 30, 2013 for this well.

Should we have a discovery at our upcoming Ship Shoal 255 prospect, we will transport the new production through this platform. We have currently classified the platform as unproved properties, as its cost is expected to be recovered through Ship Shoal 255.

Vermilion 170 Platform

Our Company-owned and operated production 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 Vermilion 170 well, which flow via the Sea Robin Pipeline to onshore processing plants. Based on current production and decline rates, the Company has determined the need to place its Vermilion 170 well on compression in early-2014, at a cost of $1.4 million, net to Contango. As of June 30, 2013, the Company had incurred all of the $1.4 million to design, build and install the compressor. As of June 30, 2013, we were producing approximately 9.5 Mmcfed, net to Contango, from this platform.

In January 2013, we identified sustained casing pressure between the production tubing and the production casing at our Vermilion 170 well. Diagnostic tests revealed that the production tubing had parted downhole requiring a workover of the well. Well production was shut-in and the original tubing and completion assembly were successfully removed. Operations were conducted to replace the tubing and restore the well, which resumed production in June 2013. For the fiscal year ended June 30, 2013, we expended approximately $12.0 million on these workover operations, net to the Company.

Other Activities

On July 30, 2013, we spud our South Timbalier 17 prospect in state of Louisiana waters with the Hercules 202 rig, and on August 22, 2013 we announced a successful well. The well was drilled to a total measured depth of approximately 11,400 feet and the wireline logs of the well indicate the presence of hydrocarbons. Estimated reserves and production rates will be dependent upon the liquids content of the formation, which will be better defined once we complete and test the well. We are proceeding with development, including securing production facilities. Estimated costs net to Contango to drill, complete and bring this well to full production status are $12.5 million. Contango has a 75% working interest (53.25% net revenue interest) before payout of all costs, and a 59.3% working interest (42.1% net revenue interest) after payout.

In June 2013, the Company was awarded Eugene Island 23 by the Bureau of Ocean Energy Management ("BOEM"), which was bid at the Central Gulf of Mexico Lease Sale 227 held on March 20, 2013. In July 2013, the Company was awarded Ship Shoal 52 and Ship Shoal 59, representing one prospect, bid at the same Lease Sale 227. The Company bid a total of approximately $1.7 million on these three blocks. We have begun the permitting process and are hopeful to drill these new prospects in the second and third quarter of calendar year 2014.

In July 2012, we spud our Ship Shoal 134 prospect ("Eagle"). On October 19, 2012, we announced that we had reached total depth on Eagle and no commercial hydrocarbons were found. The Company has plugged and abandoned this well. For the fiscal year ended June 30, 2013, we incurred approximately $28.9 million to drill, plug and abandon this well, including approximately $6.3 million in leasehold costs. During the fiscal year ended 2013, we released two leases related to this prospect.

In July 2012, we spud our South Timbalier 75 prospect ("Fang"). On October 30, 2012, we announced that we had reached total depth on Fang and no commercial hydrocarbons were found. The Company has plugged and abandoned this well. For the fiscal year ended June 30, 2013, we incurred approximately $21.1 million to drill, plug and abandon this well, including approximately $0.3 million in leasehold costs. This prospect was a farm-in and the lease was never earned as a result of the dry hole.

Prior Year Activities

In June 2012, the Company successfully acquired six leases at the Central Gulf of Mexico Lease Sale 216/222. The Company bid an aggregate amount of approximately $11 million on East Cameron 124, Eugene Island 31, Eugene

Island 260, Ship Shoal 83, Ship Shoal 255 and South Timbalier 110. The Company will have a 100% working interest in these prospects, subject to back-ins if successful. We have submitted an exploration permit for the first of these blocks, Ship Shoal 255, and have budgeted to spud this well in late-2013 at an estimated cost of $22.5 million, net to Contango.

In March 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, 2013, the Company had invested approximately $0.5

million in Brazos Area 543, which includes seismic and leasehold costs. During the year ended June 30, 2013, we recognized an impairment expense of $0.2 million related to this lease.

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 2015.

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, 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.

Republic Exploration LLC

In his capacity as sole manager of the general partner of JEX, Mr. Brad Juneau controls the activities of REX, an entity owned 34.4% by JEX, 32.3% by Contango, and 33.3% by a third party. 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. In April 2013, REX sold its 25% working interest in West Delta 36 to another partner in that well.

Offshore Properties

Contango, through its wholly-owned subsidiary Contango Operators, Inc. ("COI"), and its partially-owned subsidiary REX, conducts exploration activities in the shallow waters of the Gulf of Mexico. As of June 30, 2013, Contango, through COI and REX, had an interest in 19 offshore leases.

During the fiscal year ended June 30, 2013, the Company acquired nine lease blocks at two Central Gulf of Mexico lease sales, acquired one lease block from an independent oil and gas company, relinquished four lease blocks to the BOEM, and allowed two additional lease blocks to expire in accordance with their terms. During the fiscal year ended June 30, 2012, the Company acquired one lease block at federal lease sale and allowed one lease block to expire. During the fiscal year ended June 30, 2011, the Company purchased one lease block from an independent oil and gas 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 June 30, 2013:

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	100.00%	80.0%	Producing
Vermilion 170	87.24%	68.0%	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 June 30, 2013:

Area/Block	WI	Lease Date	Expiration Date
East Breaks 369 (Dry Hole)	(1)	Dec-03	Dec-13
South Timbalier 17	75.00%	(2)	(2)
Brazos Area 543	100.00%	Mar-12	Mar-17
East Cameron 124	100.00%	Sept-12	Sept-17
Eugene Island 31	100.00%	Oct-12	Oct-17
Ship Shoal 83	100.00%	Oct-12	(3)
South Timbalier 110	100.00%	Oct-12	Oct-17
Eugene Island 260	100.00%	Nov-12	Nov-17
Ship Shoal 255	100.00%	Dec-12	Dec-17
Eugene Island 23	100.00%	Jun-13	Jun-18
Ship Shoal 52	100.00%	Jul-13	Jul-18
Ship Shoal 59	100.00%	Jul-13	Jul-18

(1) Farm-out. COI retains a 2.41% ORRI
(2) Successful exploration well. Lease will be held by production.
(3) Submitted paperwork to relinquish in August 2013.

The Company's Eugene Island 11 block expired in December 2012. 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 obtained such permission and permits. We installed our facilities at Eugene Island 11 because that was the optimal gathering location in proximity to our wells and marketing pipelines, but we were not required to purchase the Eugene Island 11 block to place our facilities at this location.

Onshore Exploration and Properties

Kaybob Duvernay - Alberta, Canada

In April 2011, the Company committed to invest up to $20 million in Alta, a venture that was formed to acquire, explore, develop and operate onshore unconventional oil and natural gas shale assets in North America. As of June 30, 2013, we had invested approximately $14.9 million in Alta to lease over 67,000 acres in the Kaybob Duvernay, a liquids rich shale play in Alberta, Canada. In July 2013, we invested an additional approximately $0.3 million in Alta. In August 2013, Alta signed a contract to sell its interest in the Kaybob Duvernay. Proceeds from the sale are expected to be approximately $29 million, net to Contango. The sale is expected to close by October after satisfaction of a number of closing conditions. Contango has a 2% interest in Alta and a 5% interest in the Kaybob Duvernay project.

Jonah Field - Sublette County, Wyoming

In April 2012, the Company, through its wholly-owned subsidiary, Contaro Company, entered into a Limited Liability Company Agreement (as amended, the “LLC Agreement”) in connection with the formation of 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, or a 45% ownership interest in Exaro.

In August 2012, one of the other investors in Exaro exercised its right to assume $15 million of the Company's commitment, which lowered the Company's commitment to $67.5 million and its ownership interest to 37%. As of June 30, 2013, the Company had invested approximately $46.9 million in Exaro.

Exaro has entered into an Earning and Development 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 described 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.

As of June 30, 2013, the Company had invested approximately $46.9 million in Exaro, including $13.1 million that was invested during the fiscal year ended June 30, 2013. As of June 30, 2013, the Exaro-Encana venture had 55 new wells on production, producing at a rate of approximately 10.7 Mmcfed, net to Contango, plus an additional five wells that are either in the completion or fracture stimulation phase. Exaro continues to have three drilling rigs running on this project. For the fiscal year ended June 30, 2013, the Company recognized a gain of approximately $1.2 million, net of tax benefits, as a result of its investment in Exaro. See Note 7 - Investment in Exaro Energy III LLC for a detailed description of our financial condition as a result of this investment.

Tuscaloosa Marine Shale

In October 2012, the Company purchased a 25% non-operating working interest in the Crosby 12H-1 well in Wilkinson County, Mississippi, targeting the Tuscaloosa Marine Shale ("TMS"), an oil-focused shale play in central Louisiana and Mississippi. As of June 30, 2013, we had invested approximately $5.8 million in this well, including leasehold costs. This well is operated by Goodrich Petroleum Company LLC ("Goodrich"). For evaluation purposes, we drilled a pilot well, performed an open-hole evaluation and obtained a conventional core over the TMS interval. As of June 30, 2013, the Crosby 12H-1 well was producing at an 8/8ths rate of approximately 350 barrels of oil per day, with cumulative production of approximately 74,000 barrels of oil through June 30, 2013. This well has approximately 6,700 feet of usable lateral and was fracked with 25 stages.

As of June 30, 2013, the Company had invested approximately $9.1 million to lease approximately 24,000 additional acres in the TMS. In July 2013, we elected to participate with less than a 1% working interest in the CMR/Foster Creek 20-7H #1 well, which is operated by Goodrich, as a result of our acreage being pooled into a unit. In August 2013, we elected to participate with approximately a 3% working interest in the Huff 18-7H #1 well, which is also operated by Goodrich, as a result of our acreage being pooled into a unit. We plan to continue to participate in third-party operated wells with a small working interest prior to initiating an operated, high interest drilling program. The data we obtain from these wells will assist us to evaluate our TMS acreage and to develop a plan for drilling and operating future wells.

Jim Hogg County, Texas

During the fiscal year ended June 30, 2013, we expended approximately $1.4 million in an exploration program with a large south Texas mineral owner involving acreage in Jim Hogg County, Texas. We have determined this program to be unsuccessful and will not invest additional funds.

Discontinued Operations

Joint Venture Assets

In October 2009, the Company entered into a joint venture with Patara Oil & Gas LLC ("Patara") to develop Cotton Valley gas reserves in Panola County, Texas. B.A. Berilgen, a member of the Company's board of directors, was the Chief Executive Officer of Patara at the time. In May 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

In May 2011, the Company sold to Patara its 100% interest in Rexer #1 and 75% interest in Rexer-Tusa #2 for approximately $2.5 million and recognized a pre-tax loss of approximately $0.3 million. The Rexer #1 well had proved reserves of approximately 0.5 Bcfe, net to Contango, while the Rexer-Tusa #2 had not been spud at the time of sale.

The remaining 25% working interest in Rexer-Tusa #2 was sold to Patara in October 2011 for $10,000. The Company has accounted for the sale of Rexer #1 and Rexer-Tusa #2 as discontinued operations as of June 30, 2012 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, 2013 were ConocoPhillips Company (53%), Shell Trading US Company (21%), Enterprise Products Operating LLC (9%) and Exxon Mobil Oil Corporation (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 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 response to the Deepwater Horizon Incident. In January 2011, various legislative committees released their reports, 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.

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 to $100 million on certain wells, which covers control of well, pollution cleanup and consequential damages. We have increased our general liability coverage to $150 million, which covers pollution cleanup, consequential damages coverage, and third party personal injury and death. We have also increased our Oil Spill Financial Responsibility coverage 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.

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. 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 enforces the SEMS requirements through regular audits. 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 drilling contractors 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 evaluate 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
Joseph J. Romano	60	Chairman, President and Chief Executive Officer
Sergio Castro	44	Vice President, Chief Financial Officer, Treasurer and Secretary
Yaroslava Makalskaya	44	Vice President, Chief Accounting Officer and Controller
Marc L. Duncan	60	Senior Vice President - Engineering
Charles A. Cambron (1)	46	Vice President - Drilling
Michael J. Autin	54	Vice President - Production
B.A. Berilgen	65	Director
Jay D. Brehmer	48	Director
Brad Juneau	53	Director
Charles M. Reimer	68	Director
Steven L. Schoonover	68	Director

(1) Resigned effective August 22, 2013

Joseph J. Romano. Mr. Romano was elected Director, President and Chief Executive Officer of Contango in November 2012, a few months after the Company's founder, Mr. Kenneth R. Peak, received a medical leave of absence. Upon Mr. Peak's passing in April 2013, Mr. Romano was also elected Chairman. Mr. Romano assisted Mr. Peak in founding the Company in 1999. Mr. Romano has worked in the energy industry since 1977. Mr. Romano served as Senior Vice President and Chief Financial Officer of Zilkha Energy Company until its sale in 1998 and served as President and Chief Executive Officer of Zilkha Renewable Company until its sale in 2005. He currently also serves in various capacities in Zilkha-affiliated companies. He has been President and Chief Executive Officer of Olympic Energy Partners since 2005, which owns working interests in Contango's Dutch and Mary Rose fields, has been President and Chief Executive Officer of ZZ Biotech since 2006, and has been Vice President and Director of Laetitia Vineyards and Winery since 2000. Mr. Romano also served as Chief Financial Officer, Treasurer and Controller of Texas International Company from 1986 through 1988 and its Treasurer and Controller from 1982 through 1985. Prior to 1982, Mr. Romano spent five years working in the Worldwide Energy Group of the First National Bank of Chicago. He earned his BA in Economics from the University of Wisconsin in Eau Claire and an MBA from the University of Northern Illinois.

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, Chief Accounting Officer and Controller in June 2010. Ms. Makalskaya has over 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. In December 2012, Mr. Duncan was appointed Senior Vice President - Engineering. Mr. Duncan has approximately 40 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. Mr. Autin has approximately 35 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. In February 2013 he became the managing director 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.

Brad Juneau. Mr. Juneau, was elected a director of the Company in April 2012. Mr. Juneau is the sole manager of the general partner of JEX. Prior to forming JEX 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. Additionally, as a co-founder of CORE, Mr. Juneau was elected President and Chief Executive Officer of CORE in December 2012, and appointed Chairman of CORE in April 2013. Mr. Juneau holds a BS degree in petroleum engineering from Louisiana State University.

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.

Mr. Kenneth R. Peak, the Company's founder, was Chairman of the Board, Chief Executive Officer and a director of the Company since its inception in 1999. In August 2012, Mr. Peak received a medical leave of absence from his responsibilities at the Company. Mr. Peak passed away in April 2013. Mr. Peak also co-founded Contango ORE, Inc. in 2010, and from its inception until August 2012 was its Chairman and 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 founding 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 was also a director of Patterson-UTI Energy, Inc., a provider of onshore contract drilling services to exploration and production companies in North America.

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. Each non-employee director of the Company receives a quarterly retainer of $28,000 payable in cash, with no stock option or common stock grants. There are no additional payments for meetings attended or being chairman of a committee. During fiscal year 2011, 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 February 29, 2016.

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 1A. Risk Factors

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

RISK FACTORS RELATING TO CONTANGO

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

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

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

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

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

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

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

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

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

COI, a wholly-owned subsidiary of the Company, was formed for the purpose of drilling and operating exploration wells in the Gulf of Mexico. Drilling activities are subject to numerous risks, including the significant risk that no commercially productive hydrocarbon reserves will be encountered. The cost of drilling, completing and operating wells and of installing production facilities and pipelines is often uncertain. Drilling costs could be significantly higher if we encounter difficulty in drilling offshore exploration wells. The Company’s drilling operations may be curtailed, delayed, canceled or negatively impacted as a result of numerous factors, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery or availability of material, equipment and fabrication yards. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs,
drilling vessels, supply boats and personnel experienced in the oil and gas industry in general, and the offshore oil and gas industry in particular. This may lead to difficulty and delays in consistently obtaining certain services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates and scheduling equipment fabrication at factories and

fabrication yards. This, in turn, may lead to projects being delayed or experiencing increased costs. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or we may not recover all or any of our investment. The risk of significant cost overruns, curtailments, delays, inability to reach our target reservoir and other factors detrimental to drilling and completion operations may be higher due to our inexperience as an operator.

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

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

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

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

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

The vast majority of our capital investments is primarily focused in offshore Gulf of Mexico exploration prospects, which may result in a total loss of our investment. Furthermore, even our productive wells may not result in profitable operations. Gulf of Mexico exploration efforts have been undertaken for over 60 years and remaining prospects are at deeper horizons that are more expensive to drill and often in much deeper water depths. Accordingly, as a result, a number of companies have shifted their focus to onshore “shale plays.” The Company’s continuing focus on the Gulf of Mexico will result in significant dry hole costs, perhaps in excess of $30 million for one well, which significantly concentrates and increases our risk profile.

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

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

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

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

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

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

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

Approximately 89.6% of our reserves are assigned to our Dutch and Mary Rose field which has ten producing well bores concentrated primarily in one reservoir and is producing through one production platform. Reserve assessments based on only ten well bores in one reservoir are subject to significantly greater risk of being shut-in for a variety of weather, platform and pipeline difficulties. In addition, the risk of a downward revision in our reserve estimates is also greater.

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

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

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

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

- Unexpected drilling conditions.
- Blowouts, fires or explosions with resultant injury, death or environmental damage.
- Pressure, temperature or other irregularities in formations.
- Equipment failures and/or accidents caused by human error.
- Tropical storms, hurricanes and other adverse weather conditions.
- Compliance with governmental requirements and laws, present and future.
- Shortages or delays in the availability of drilling rigs and the delivery of equipment.
- Our turnkey drilling contracts reverting to a day rate contract or our turnkey contractor electing to terminate the

turnkey contract would significantly increase the cost and risk to the Company.

• Problems at third-party operated platforms, pipelines and gas processing facilities over which we have no control.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. Poor results from our drilling activities would materially and adversely affect our future cash flows and results of operations. In addition, as a "successful efforts" company, we choose to account for unsuccessful exploration efforts (the drilling of "dry holes") and seismic costs as a current expense of operations, which immediately impacts our earnings. Significant expensed exploration charges in any period would materially adversely affect our earnings for that period and cause our earnings to be volatile from period to period.

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

A blowout, rupture or spill of any magnitude would present serious operational and financial challenges. All of the Company's operations in the Gulf of Mexico shelf are in water depths of less than 300 feet and less than 50 miles from the coast. Such proximity to the shore-line increases the probability of a biological impact or damaging the fragile eco-system in the event of released condensate.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.
Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions in the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including countries in the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.
The Environmental Protection Agency (the "EPA") has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. EPA has proposed such greenhouse gas regulations and may issue final rules at a subsequent date.
Several decisions have been issued by courts that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

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

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

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

• Blowouts, fires and explosions.
• Surface cratering.
• Uncontrollable flows of underground natural gas, oil or formation water.
• Natural disasters.
• Pipe and cement failures.
• Casing collapses.
• Stuck drilling and service tools.
• Reservoir compaction.
• Abnormal pressure formations.
• Environmental hazards such as natural gas leaks, oil spills, pipeline ruptures or discharges of toxic gases.

• Capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which we have no control.
• Repeated shut-ins of our well bores could significantly damage our well bores.
• Required workovers of existing wells that may not be successful.

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

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

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

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

Not hedging our production may result in losses.

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

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

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

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

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

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

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

Proposed United States federal budgets and pending legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

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

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

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

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

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

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

As a result of the Deepwater Horizon Incident in 2010, the Department of the Interior issued additional safety and performance standards as well as rigorous monitoring and testing requirements for offshore drilling. In addition, various Congressional committees began pursuing legislation to regulate drilling activities, establish safety requirements and increase liability for oil spills.

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

• Increase the costs of drilling exploratory and development wells.

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

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

Current regulatory requirements and permitting procedures have significantly delayed our ability to obtain permits to drill new wells in offshore waters.

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

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

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

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

The BSEE is the federal agency responsible for overseeing the safe and environmentally responsible development of energy and mineral resources on the OCS. They are responsible for leading the most aggressive and comprehensive reforms to offshore oil and gas regulation and oversight in U.S. history. Their reforms have tightened requirements for everything from well design and workplace safety to corporate accountability. One of the many reforms includes implementing a SEMS program. This program requires operators to identify, address, and manage safety and environmental hazards during the design, construction, start-up, operation, inspection, and maintenance of all new and existing facilities. Facilities must be designed, constructed, maintained, monitored, and operated in a manner compatible with industry codes, consensus standards, and all
applicable governmental regulations. Failure to comply with the SEMS program may force us to cease operations in the Gulf of Mexico.

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

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

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

It is customary in our industry to recover natural gas and oil from shale and other formations through the use of horizontal drilling combined with hydraulic fracturing. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations using water, sand and other additives pumped under high pressure into the formation. We intend to use hydraulic fracturing as a means to increase the productivity of the onshore wells that we drill and complete.

The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Several states, including Pennsylvania, Texas, Colorado, Montana, New Mexico and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

Additionally, the EPA has asserted federal regulatory authority over hydraulic fracturing activities involving diesel fuel (specifically, when diesel fuel is utilized in the stimulation fluid) under the Safe Drinking Water Act and is completing the process of drafting guidance documents related to this newly asserted regulatory authority. There are also certain governmental reviews either underway or being proposed that focus on shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate such activities. The EPA has published proposed New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP") that, if adopted as proposed, would amend existing NSPS and NESHAP standards for oil and gas facilities as well as create new NSPS standards for oil and gas production, transmission and distribution facilities. The EPA has also proposed regulations focused on reducing emissions of certain air pollutants by the oil and gas industry, including volatile organic compounds, sulfur dioxide and certain air toxics.

Certain environmental and other groups have suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether additional federal, state or local laws or regulations will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

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

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

• Timing and amount of capital expenditures.

• The operator’s expertise and financial resources.
• Approval of other participants in drilling wells.
• Selection of technology.

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

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy is highly dependent on our management team, as well as certain key geoscientists, geologists, engineers and other professionals engaged by us. We are highly dependent on the services provided by JEX. The loss of key members of our management team, JEX or other highly qualified technical professionals could adversely affect our ability to effectively manage our overall operations or successfully execute current or future business strategies which may have a material adverse effect on our business, financial condition and operating results.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.
We expect to evaluate and, where appropriate, pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of natural gas and oil properties requires an assessment of:

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

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

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

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

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

RISK FACTORS RELATED TO THE MERGER
The transactions contemplated by the Merger Agreement are subject to conditions, including certain conditions that may not be satisfied, or completed on a timely basis, if at all.

The Merger is subject to a number of conditions beyond Contango's and Crimson's control that may prevent, delay or otherwise materially adversely affect its completion. We cannot predict whether and when these other conditions will be satisfied. Any delay in completing the Merger could cause us not to realize some or all of the synergies that we expect to achieve if the Merger is successfully completed within its expected time frame.
Failure to complete the Merger could negatively impact our future business and financial results.

We cannot make any assurances that we will be able to satisfy all of the conditions to the Merger or succeed in any litigation brought in connection with the Merger. If the Merger is not completed, our financial results may be adversely affected and we will be subject to several risks, including but not limited to:

- Being required to pay a termination fee of $28 million under certain circumstances provided in the Merger Agreement;

- Payment of costs relating to the Merger, such as legal, accounting, financial advisor and printing fees, whether or not the Merger is completed;
- Having had the focus of our management on the Merger instead of on pursuing other opportunities that could have

been beneficial to the Company; and
•Being subject to litigation related to any failure to complete the Merger.

If the Merger is not completed, we cannot assure our stockholders that these risks will not materialize and will not materially and adversely affect our business, financial results and stock prices.

Uncertainties associated with the Merger may cause a loss of management personnel and other key employees.

We are dependent on the experience and industry knowledge of our officers and other key employees to execute our business plans. The combined company's success after the Merger will depend in part upon the ability of Contango and Crimson to retain key management personnel and other key employees. Current and prospective employees of Contango and Crimson may experience uncertainty about their roles within the combined company following the Merger, which may have an adverse effect on the ability of each of Contango and Crimson to attract or retain key management and other key personnel. Accordingly, no assurance can be given that the combined company will be able to attract or retain key management personnel and other key employees of Contango and Crimson to the same extent that Contango and Crimson have previously been able to attract or retain their own employees.

The failure to integrate successfully the businesses of Contango and Crimson in the expected time frame would adversely affect the combined company's future results following the Merger.

The Merger involves the integration of two companies that have previously operated independently. The success of the Merger will depend, in large part, on the ability of the combined company following the Merger to realize the anticipated benefits, including synergies, cost savings, innovation and operational efficiencies, from combining the businesses of Contango and Crimson. To realize these anticipated benefits, the businesses of Contango and Crimson must be successfully integrated. This integration will be complex and time-consuming. The failure to integrate successfully and to manage successfully the challenges presented by the integration process may result in the combined company not achieving the anticipated benefits of the Merger.

Our stockholders will have a reduced ownership and voting interest in the combined company after the Merger.

If the Merger occurs, each Contango stockholder will remain a stockholder of Contango with a percentage ownership of the combined company that will be smaller than the stockholder's percentage of Contango prior to the Merger. As a result of these reduced ownership percentages, Contango stockholders will have less voting power in the combined company than they now have with respect to Contango.

The future results of the combined company could suffer if the combined company does not effectively manage its expanded operations following the Merger.

Following the Merger, the size of the business of the combined company will increase significantly beyond the current size of either Contango's or Crimson's business. The combined company's future success depends, in part, upon its ability to manage this expanded business, which could pose challenges for management, including challenges related to the management and monitoring of new operations and associated increased costs and complexity. There can be no assurances that the combined company will be successful or that it will realize the expected operating efficiencies, cost savings, revenue enhancements and other benefits currently anticipated from the Merger.

The combined company's debt may limit its financial flexibility.

Contango currently has no amounts outstanding under its credit facility and traditionally has carried minimal balances of long-term debt. Following the Merger, it is expected that the combined company will have more long-term debt. In addition, the combined company may incur additional debt from time to time in connection with the financing of operations, acquisitions, recapitalizations and refinancings. The level of the combined company's debt could have several important effects on future operations, including, among others:

• If a portion of the combined company's cash is applied to the payment of principal or interest on the debt, less will be available for other purposes;

- Credit-rating agencies may change in the future with respect to the combined company, their ratings of that entity's debt and other obligations, which in turn impacts the costs, terms and conditions and availability of financing;
- Covenants contained in the combined company's existing and future debt arrangements will require the combined company to meet financial tests that may affect its flexibility in planning for and reacting to changes in its business, including possible acquisition opportunities;

- The combined company's ability to obtain additional financing for capital expenditures, acquisitions, general corporate and other purposes may be limited or burdened by increased costs or more restrictive covenants;
- The combined company may be at a competitive disadvantage to similar companies that have less debt;
- The combined company's vulnerability to adverse economic and industry conditions may increase; and
- The combined company may face limitations on its flexibility to plan for and react to changes in its business and the industries in which it operates.

Item 1B. Unresolved Staff Comments

None

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,		
	2013	2012	2011
Property acquisition costs:		(thousands)	
Unproved	$16,130	$5,404	$2,802
Proved	102	381	10,135
Exploration costs	47,584	1,154	14,016
Development costs	11,758	10,350	39,211
Total costs	$75,574	$17,289	$66,164

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

	Year Ended June 30,		
	2013	2012	2011
		(thousands)	
Property acquisition costs	$—	$—	$—
Exploration costs	—	—	—
Development costs	46,972	785	—
Company's 37% share of costs incurred	$46,972	$785	$—

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,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive (onshore)	1	0.3	—	—	—	—
Productive (offshore)	—	—	—	—	1	1.0
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	2	2.0	—	—	1	1.0
Total	3	2.3	—	—	2	2.0

	Year Ended June 30,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Developmental Wells:						
Productive (onshore)	—	—	—	—	9	7.5
Productive (offshore)	—	—	—	—	—	—
Non-productive (onshore)	—	—	—	—	—	—
Non-productive (offshore)	—	—	—	—	—	—
Total	—	—	—	—	9	7.5

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 joint venture wells with Patara. The Rexer #1 well and joint venture wells with Patara were sold in May 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, 2013:

	Developed Acreage (1)(2)		Undeveloped Acreage (1)(3)	
	Gross (4)	Net (5)	Gross (4)	Net (5)
Onshore (TMS)	1,342	336	24,372	24,372
Offshore Gulf of Mexico	17,298	12,867	50,561	50,534
Total	18,640	13,203	74,933	74,906

(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 625 net developed 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, 2013:

	Total Productive Wells (1)	
	Gross (2)	Net (3)
Natural gas (onshore)	—	—
Natural gas (offshore)	12	6.50
Oil (onshore)	1	0.25
Oil (offshore)	—	—
Total	13	6.75

(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.

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Natural Gas and Oil Reserves

The following table presents our estimated net proved natural gas and oil reserves at June 30, 2013, based on reserve reports generated by William M. Cobb & Associates, Inc. (“Cobb”) and W.D. Von Gonten and Company ("Von Gonten"). The Company believes that having independent and well respected third-party engineering firms 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. Joseph J. Romano, the Company’s Chief Executive Officer, has primary responsibility for the preparation of the reserve report. Mr. Romano has been in the energy industry for over 35 years, but also relies on others with technical backgrounds in a collaborative effort, all of who provide input to the independent third-party engineers. Mr. Brad Juneau, one of the Company’s directors, 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 engineers and assist in reviewing the reports.

The qualifications of the technical individuals at Cobb and Von Gonten responsible for overseeing the preparation of our reserve estimates are set forth below.

William M. Cobb & Associates, Inc.

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

W.D.Von Gonten and Company

- Over 13 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

Each of Cobb and Von Gonten 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, 2013:

	Developed	Undeveloped	Total
Contango Oil & Gas Reserves (1)			
Natural gas (MMcf)	146,518	2,489	149,007
Oil and condensate (MBbls)	2,297	31	2,328
Natural gas liquids (MBbls)	4,078	66	4,144
Total proved reserves (MMcfe)	184,768	3,071	187,839
Reserves Attributable to our 37% Investment in Exaro (2)			
Natural gas (MMcfe)	30,174	—	30,174
Total (Mmcfe)	214,942	3,071	218,013

(1) Reserves prepared by William M. Cobb & Associates, Inc.
(2) Reserves prepared by W.D. Von Gonten and Company

Prior Year Reserves

Our estimated net proved natural gas, oil and natural gas liquids reserves as of June 30, 2010, 2011, 2012 and 2013 are disclosed on page F-26 and were based on reserve reports generated by Cobb, while the reserves associated with our 37% investment in Exaro were prepared by Von Gonten. 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, 2013, the Company had approximately 3.1 Bcfe of PUDs related to Mary Rose #6, a rate acceleration well on state of Louisiana acreage. Our plan is to develop this PUD reserve prior to December 31, 2016, which is five years from the initial date of disclosure of this PUD reserve.

The Mary Rose #6 rate acceleration well will be drilled in the main Cib Op reservoir. This well provides significant acceleration benefits but minimal incremental reserves. The incremental net PV-10 for this well, as of June 30, 2013, is approximately $26.6 million. However, the incremental net reserves are only approximately 2,489 MMcf and 97 MBbls of condensate and liquids. The incremental net reserves are modest because the main Cib Op reservoir is a depletion drive retrograde gas reservoir. The condensate yield declines as reservoir pressure declines. Our reservoir engineer's simulation model indicates that the timing of the pressure depletion, and the distribution of that depletion across the field, will have an effect on all of the wells in communication with the Mary Rose #6. The effect of accelerating the pressure depletion, and changing the take points in the reservoir, is that more of the condensate "condenses" in the reservoir before it can be produced into the wellbores.

The Mary Rose #6 PUD reserves are calculated incrementally. The field-wide simulation model is run first without the
Mary Rose #6 well to generate a total field gas and condensate projection. The model is then run again with the Mary Rose #6 well included. The difference between these two cases is the incremental PUD reserve case. Of the gas volumes the Mary Rose #6 well is projected to produce, the majority comes from other wells in the field, such that the incremental gas recovery for the Mary Rose #6 well is much less.

The following table presents the changes in our total proved undeveloped reserves for the fiscal year ended June 30, 2013 (MMcfe):

	Mary Rose #6
Proved undeveloped reserves as of June 30, 2012	6,197
Change in estimate	(3,126)
Proved undeveloped reserves as of June 30, 2013	3,071

Pre-Tax Net Present Value

The Company's pre-tax net present value, discounted at 10%, for its reserves is approximately $550.3 million. This figure 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, 2013 was based on $3.44 per million British thermal units ("MMbtu") for natural gas at the NYMEX, $91.57 per barrel of oil at the West Texas Intermediate Posting, and $39.50 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, 2013 is as follows (in thousands):

	June 30, 2013
Pre-tax net present value, discounted at 10%	$550,336
Future income taxes, discounted at 10%	(192,819)
Standardized measure of discounted future net cash flows	$357,517

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

Item 3. Legal Proceedings

Several class action lawsuits have been brought by Crimson stockholders challenging the proposed Merger and seeking, among other things, injunctive relief to enjoin the defendants from completing the Merger on the agreed-upon terms, compensatory damages, and costs and disbursements relating to the lawsuits. Various combinations of Crimson, Contango, members of Crimson's board of directors, and members of Crimson management have been named as defendants in these lawsuits. It is possible that additional similar lawsuits may be filed.

The known plaintiffs in these lawsuits, based on the most current information provided by Crimson, collectively own a very small percentage of the total outstanding shares of Crimson common stock. The lawsuits allege, among other things, that Crimson's board of directors failed to take steps to obtain a fair price, failed to properly value Crimson, failed to protect against alleged conflicts of interest, failed to conduct a reasonably informed evaluation of whether the transaction was in the best interests of stockholders, failed to fully disclose all material information to stockholders, acted in bad faith and for improper motives, engaged in self-dealing, discouraged other strategic alternatives, took steps to avoid competitive bidding, and agreed to allegedly unreasonable deal protection mechanisms, including the no-shop and fiduciary-out provisions and termination fee. The lawsuits also allege that Contango aided and abetted the other defendants in violating duties to the Crimson stockholders. The lawsuits seek damages and injunctive relief. Contango and Crimson believe that these lawsuits are without merit and intend to contest them vigorously.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

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

	High	Low
Fiscal Year 2012:		
Quarter ended September 30, 2011	$67.25	$52.25
Quarter ended December 31, 2011	$69.75	$51.54
Quarter ended March 31, 2012	$65.08	$56.73
Quarter ended June 30, 2012	$60.24	$51.00
Fiscal Year 2013:		
Quarter ended September 30, 2012	$61.16	$49.11
Quarter ended December 31, 2012	$52.64	$38.10
Quarter ended March 31, 2013	$46.05	$36.27
Quarter ended June 30, 2013	$40.49	$33.50

On June 30, 2013, we had 69 registered shareholders. In November 2012, the Board of the Company declared a special dividend of $2.00 per share of common stock to be paid on December 17, 2012 to each holder of record of the Company's common stock as of the close of business on December 10, 2012. We have not declared any further cash dividends on our shares of common stock. Any future decision to pay dividends on our common stock will be at the discretion of our board and will depend upon our financial condition, results of operations, capital requirements, and other factors our board may deem relevant.

The following table sets forth information about our equity compensation plans at June 30, 2013:

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

The Company's 1999 Stock Incentive Plan (the "1999 Plan") expired in August 2009. The final remaining outstanding options were net-settled with the Company in February 2012 and no options remain outstanding.

On September 15, 2009, the Company's Board of Directors (the "Board") adopted the Contango Oil & Gas Company Equity Compensation Plan (the "2009 Plan"), which was approved by shareholders on November 19, 2009. Under the 2009 Plan, the Board may grant restricted stock and option awards to officers, directors, employees or consultants of the Company. Awards made under the 2009 Plan are subject to such restrictions, terms and conditions, including forfeitures, if any, as may be determined by the Board. As of June 30, 2013, all options issued under the 2009 Plan had been exercised. The Company has not issued any restricted stock under the 2009 Plan.

In February 2012, the Company net-settled 45,000 stock options from two officers for a total of approximately $465,000. During the fiscal year ended June 30, 2011, the Company purchased 172,544 shares of its common stock. Of this amount, 152,544 shares were purchased from three officers of the Company, one member of the Board, one employee, and one consultant for a total of approximately $8.9 million. All purchases were approved by the Board under the Company's share repurchase programs described below and were completed at the closing price of the Company's common stock on the date of purchase.

Share Repurchase Programs

$100 Million Share Repurchase Program

In September 2008, the Company's board of directors approved a $100 million share repurchase program which concluded in October 2011. Under this share repurchase program, the Company purchased a total of 2,157,278 shares of common stock at an average price of $46.35 per share. All shares were purchased in the open market or through privately negotiated transactions when we believed the Company's stock price to be undervalued. The purchases were made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market. Repurchased shares of common stock became authorized but unissued shares, and may be issued in the future for general corporate and other purposes.

$50 Million Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program, effective upon completion of purchases under the Company's $100 million share repurchase program. The repurchases are subject to the same terms and conditions as repurchases made under the $100 million share repurchase program. During the fiscal year ended June 30, 2013, the Company purchased the below listed shares under its $50 million share repurchase program:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Shares that may yet be Purchased Under Program
October 2 - 5, 2012	97,496	$50.82	197,877	$39.7 million

In addition to the above, in February 2012 the Company net-settled 45,000 stock options from two officers for a total of approximately $465,000. In total, under both share repurchase programs combined as of June 30, 2013, the Company had invested approximately $110.8 million to purchase 2,355,155 shares of its common stock at an average cost per share of $46.84, and 45,000 stock options. As of June 30, 2013, the Company had 15,194,952 shares of common stock outstanding and no options.

The following graph compares the yearly percentage change from June 30, 2008 until June 30, 2013 in the cumulative total stockholder return on our common stock to the cumulative total return on the S&P Smallcap 600 Index and a peer group of five independent oil and gas exploration companies selected by us. In previous years, the companies in our selected peer group included ATP Oil & Gas Corp., McMoRan Exploration Company, Callon Petroleum, Energy XXI (Bermuda) Limited, and W&T Offshore, Inc. ("Old Peer Group").

In August 2012, ATP Oil & Gas Corp. filed for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of Texas, and in June 2013 McMoRan Exploration Company ceased trading on the NYSE as a result of their merger with Freeport-McMoRan Copper & Gold, Inc. As a result, we deleted these two companies from our Old Peer Group and replaced them with two new companies. The companies in our selected peer group now include Stone Energy Corporation, SandRidge Energy Inc., Callon Petroleum, Energy XXI (Bermuda) Limited and W&T Offshore, Inc. ("New Peer Group").

Our common stock began trading on the NYSE MKT (previously American Stock Exchange) on January 19, 2001 and before that had traded on the Nasdaq over-the-counter Bulletin Board. The graph assumes that a $100 investment was made in our common stock and each index on June 30, 2008, adjusted for stock splits and dividends. The stock performance for our common stock is not necessarily indicative of future performance.

	6/30/2008	6/30/2009	6/30/2010	6/30/2011	6/30/2012	6/30/2013
Contango Oil & Gas Company	100.00	45.73	48.16	62.89	63.71	38.22
S&P Smallcap 600	100.00	74.69	92.34	126.53	128.34	160.65
Old Peer Group	100.00	15.43	23.80	55.71	43.95	35.39
New Peer Group	100.00	13.69	14.45	32.03	23.34	18.16

Item 6. Selected Financial Data

The following selected financial data for the years ended June 30, 2013, 2012, 2011, 2010 and 2009 have been derived from the audited consolidated financial statements of Contango contained in our Annual Report on Form 10-K for the applicable fiscal year. The selected consolidated financial data (not including proved reserve information) set forth below is for continuing operations and should be read in conjunction with Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and with the consolidated financial statements and notes to those consolidated financial statements included elsewhere in this Form 10-K.

	Year Ended June 30,				
	2013	2012	2011	2010	2009
Financial Data:	(Dollar amounts in thousands, except per share amounts)				
Revenues:					
Natural gas and oil sales	$127,201	$179,272	$201,721	$159,010	$190,656
Income from continuing operations (a)	$(9,720)	$59,213	$64,459	$50,166	$55,861
Discontinued operations, net of income taxes	—	(824)	574	(480)	—
Net income attributable to common stock	$(9,720)	$58,389	$65,033	$49,686	$55,861
Net income (loss) per share:					
Basic					
Continuing operations	$(0.64)	$3.84	$4.11	$3.17	$3.41
Discontinued operations	—	(0.05)	0.04	(0.03)	—
Total	$(0.64)	$3.79	$4.15	$3.14	$3.41
Diluted					
Continuing operations	$(0.64)	$3.84	$4.10	$3.11	$3.35
Discontinued operations	—	(0.05)	0.04	(0.03)	—
Total	$(0.64)	$3.79	$4.14	$3.08	$3.35
Weighted average shares outstanding:					
Basic	15,221	15,423	15,665	15,831	16,363
Diluted	15,221	15,425	15,713	16,157	16,690
Working capital	$112,466	$140,901	$126,654	$41,385	$43,232
Capital expenditures	$80,418	$20,844	$69,993	$97,703	$45,742
Cash dividends (b)	$30,510	$—	$—	$—	$—
Long term debt	$—	$—	$—	$—	$—
Shareholders' equity	$419,154	$464,339	$426,623	$377,330	$349,364
Total assets	$576,461	$624,654	$636,930	$592,266	$517,042
Proved Reserve Data:					
Total proved reserves (Mmcfe) (c)	187,839	256,567	296,729	314,027	355,046
Pre-tax net present value (discounted at 10%)	$550,336	$730,222	$981,041	$970,442	$889,865
Standardized measure (c)	$357,517	$513,932	$717,135	$712,094	$638,091

(a) During the fiscal year ended June 30, 2013, the Company drilled two dry holes resulting in exploration expenses of approximately $50 million, including leasehold costs. Also during the fiscal year ended June 30, 2013, Contango revised estimated proved reserves at Ship Shoal 263, resulting in non-cash impairment expenses of approximately $12.0 million.
Additionally, the Company completed a workover on its Vermilion 170 well at a cost of approximately $12.0 million.

(b) On November 29, 2012, the board of directors declared a one-time special dividend of $2.00 per share of common stock which was paid on December 17, 2002.

(c) During the fiscal year ended June 30, 2013, the Company's proved reserves decreased by approximately 68.7 Bcfe and its standardized measure decreased by approximately $156.4 million. This decrease is attributable to production of 24.4 Bcfe during the period, and a decrease of approximately 44.8 Bcfe in the estimated reserves at our Dutch, Mary Rose, Vermilion 170, and Ship Shoal 263 wells due to new information obtained by our reservoir engineer, offset by an increase of 0.5 Bcfe due to our onshore discovery at Crosby 12H-1 in the TMS. During the fiscal year ended June 30, 2012, the Company's proved reserves decreased by approximately 40.2 Bcfe and its standardized measure decreased by approximately $203.2 million. This decrease is attributable to production of 31.3 Bcfe during the period, and a decrease of approximately 8.9 Bcfe in the estimated reserves at our Dutch, Mary Rose, and Vermilion 170 wells due to new information obtained.

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, Texas based, independent natural gas and oil company. The Company's core business is to explore, develop, produce and acquire natural gas and oil properties offshore in the shallow waters of the Gulf of Mexico. COI, our wholly-owned subsidiary, acts as operator on our offshore properties. Contango has additional onshore investments in i) Alta Resources Investments, LLC, whose primary area of focus is the liquids-rich Kaybob Duvernay in Alberta, Canada; ii) Exaro Energy III LLC, which is primarily focused on the development of proved natural gas reserves in the Jonah Field in Wyoming; and iii) the Tuscaloosa Marine Shale where we own approximately 24,000 acres.

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, producing properties offshore in the Gulf of Mexico have high initial production rates, followed by steep declines. 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 replace any offshore reserves during the fiscal year ended June 30, 2013 or 2012. During fiscal year 2013, the Company drilled two dry holes at Ship Shoal 134 ("Eagle") and South Timbalier 75 ("Fang"). During fiscal year 2012, the Company did not drill any wells. Our permits to spud Eagle and 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. In June 2012 and March 2013, the Company successfully acquired nine lease blocks at two Gulf of Mexico Lease Sales. 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.

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 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

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.
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 offshore 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 table below sets forth our average net daily production data in Mmcfed from our offshore wells for each of the periods indicated:

	Three Months Ended				
	June 30, 2012	September 30, 2012	December 31, 2012	March 31, 2013	June 30, 2013
Dutch and Mary Rose wells	67.5	54.2	57.2	59.5	57.2
Ship Shoal 263 well	7.6	3.5	2.6	0.9	0.6
Vermilion 170 well	15.5	10.5	12.9	3.6	4.0
Non-operated wells	0.2	—	—	0.6	0.4
	90.8	68.2	72.7	64.6	62.2

Dutch and Mary Rose Wells

- Production at our Dutch and Mary Rose wells has been fairly consistent over the past year. As of June 30, 2013, the ten Dutch and Mary Rose wells were flowing approximately 54.4 Mmcfed, net to Contango.

Ship Shoal 263 Well

- Production at this well has been slowly decreasing since 2011 due to overheating, scaling problems, and water production. The well has also been shut-in several times for production logging and chemical treatment. We believe that this well may be fully depleted in the next twelve months. The well reached payout during fiscal year 2012. We will continue producing this well as long as it is economical. As of June 30, 2013, the well was flowing at approximately 0.7 Mmcfed, net to Contango.

- During the fiscal year ended June 30, 2013, due to the decline in production from this well, our reservoir engineer revised his estimated net proved natural gas and oil reserves from this well. As a result, the net book value of our Ship Shoal 263 well exceeded the future undiscounted cash flows associated with its reserves. Accordingly, the Company recognized an impairment expense of approximately $12.0 million for the fiscal year ended June 30, 2013.

Vermilion 170 Well

- In January 2013, we identified sustained casing pressure between the production tubing and the production casing at our Vermilion 170 well. Diagnostic tests revealed that the production tubing had parted downhole requiring a workover of the well. Well production was shut-in and the original tubing and completion assembly were successfully removed. Operations were conducted to replace the tubing and restore the well, which resumed production in June 2013. As of June 30, 2013, this well was flowing at approximately 9.5 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, 2013, 2012 and 2011. 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,			Year Ended June 30,		
	2013	2012	%	2012	2011	%
Revenues:	(thousands)			(thousands)		
Natural gas sales	$66,441	$73,068	(9)%	$73,068	$106,781	(32)%
Condensate sales	$39,009	$69,547	(44)%	$69,547	$61,862	12%
NGL sales	$21,751	$36,657	(41)%	$36,657	$33,078	11%
Total revenues	$127,201	$179,272	(29)%	$179,272	$201,721	(11)%
Annual Production:						
Natural gas (million cubic feet)						
Dutch and Mary Rose field	16,152	18,303	(12)%	18,303	20,589	(11)%
Vermilion 170 field	2,054	3,098	(34)%	3,098	—	100%
Other fields	452	2,216	(80)%	2,216	3,679	(40)%
Total natural gas	18,658	23,617	(21)%	23,617	24,268	(3)%
Oil and condensate (thousand barrels)						
Dutch and Mary Rose field	263	347	(24)%	347	456	(24)%
Vermilion 170 field	51	123	(59)%	123	—	100%
Other fields	48	145	(67)%	145	217	(33)%
Total oil and condensate	362	615	(41)%	615	673	(9)%
Natural gas liquids (thousand gallons)						
Dutch and Mary Rose field	21,568	21,452	1%	21,452	25,389	(16)%
Vermilion 170 field	3,391	5,390	(37)%	5,390	—	100%
Other fields	270	959	(72)%	959	1,537	(38)%
Total natural gas liquids	25,229	27,801	(9)%	27,801	26,926	3%
Total (million cubic feet equivalent)						
Dutch and Mary Rose field	20,811	23,450	(11)%	23,450	26,952	(13)%
Vermilion 170 field	2,844	4,606	(38)%	4,606	—	100%
Other fields	779	3,223	(76)%	3,223	5,201	(38)%
Total production	24,434	31,279	(22)%	31,279	32,153	(3)%
Daily Production:						
Natural gas (million cubic feet per day)						
Dutch and Mary Rose field	44.3	50.0	(12)%	50.0	56.4	(11)%
Vermilion 170 field	5.6	8.4	(34)%	8.4	—	100%
Other fields	1.2	6.1	(80)%	6.1	10.1	(40)%
Total natural gas	51.1	64.5	(21)%	64.5	66.5	(3)%
Oil and condensate (thousand barrels per day)						
Dutch and Mary Rose field	0.7	0.9	(24)%	0.9	1.2	(24)%
Vermilion 170 field	0.2	0.4	(59)%	0.4	—	100%
Other fields	0.1	0.4	(67)%	0.4	0.6	(33)%
Total oil and condensate	1.0	1.7	(41)%	1.7	1.8	(9)%

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	Year Ended June 30, 2013	2012	%	Year Ended June 30, 2012	2011	%
Daily Production (continued):						
Natural gas liquids (thousand gallons per day)						
Dutch and Mary Rose field	59.1	58.6	1 %	58.6	69.6	(16)%
Vermilion 170 field	9.3	14.8	(37)%	14.8	—	100 %
Other fields	0.7	2.6	(72)%	2.6	4.2	(38)%
Total natural gas liquids	69.1	76.0	(9)%	76.0	73.8	3 %
Total (million cubic feet equivalent per day)						
Dutch and Mary Rose field	56.9	63.8	(11)%	63.8	73.6	(13)%
Vermilion 170 field	8.1	12.8	(38)%	12.8	—	100 %
Other fields	1.9	8.9	(76)%	8.9	14.5	(38)%
Total production	66.9	85.5	(22)%	85.5	88.1	(3)%
Average Sales Price:						
Natural gas (per thousand cubic feet)	$3.56	$3.10	15 %	$3.10	$4.40	(30)%
Oil and condensate (per barrel)	$107.75	$112.75	(4)%	$112.75	$91.98	23 %
Natural gas liquids (per gallon)	$0.86	$1.32	(35)%	$1.32	$1.23	7 %
Total (per thousand cubic feet equivalent)	$5.21	$5.73	(9)%	$5.73	$6.27	(9)%
Expenses (thousands):						
Operating expenses	$31,907	$25,183	27 %	$25,183	$25,691	(2)%
Exploration expenses	$51,748	$346	*	$346	$9,751	(96)%
Depreciation, depletion and amortization	$41,060	$49,052	(16)%	$49,052	$52,198	(6)%
Impairment of natural gas and oil properties	$14,845	$—	100 %	$—	$1,786	(100)%
General and administrative expenses	$14,364	$10,418	38 %	$10,418	$12,341	(16)%
Other income (expense), net	$9,665	$(312)	*	$(312)	$(157)	99 %
Gain (loss) from affiliates (net of taxes)	$1,241	$(449)	(376)%	$(449)	$—	100 %
Selected data per Mcfe:						
Operating expenses	$1.30	$0.81	60 %	$0.81	$0.80	1 %
General and administrative expenses	$0.59	$0.33	79 %	$0.33	$0.38	(13)%
Depreciation, depletion and amortization of natural gas and oil properties	$1.65	$1.54	7 %	$1.54	$1.61	(4)%

* Greater than 1,000%

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. The Company did not have any discontinued operations for the fiscal year ended June 30, 2013.

Natural Gas, Oil and NGL Sales and Production. 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 $127.2 million for the year ended June 30, 2013, compared to revenues of approximately $179.3 million for the year ended June 30, 2012. This decrease in revenues was primarily attributable to a decrease in natural gas, condensate and NGL production, further compounded by a lower average equivalent sales price received for the period.

Our net natural gas production for the year ended June 30, 2013 was approximately 51.1 Mmcfd, down from approximately 64.5 Mmcfd for the year ended June 30, 2012. Additionally, net oil production decreased from 1,700 barrels per day to 1,000 barrels per day, while NGL production decreased from approximately 76,000 gallons per day to 69,100 gallons per day. In total, equivalent production decreased from 85.5 Mmcfed to 66.9 Mmcfed. This decrease in natural gas, oil and NGL production was principally attributable to our Vermilion 170 well which was shut-in for approximately six months this fiscal year for workover operations, our Ship Shoal 263 well which has been quickly depleting over the past year, and our Mary Rose #5 well which has been producing intermittently during most of the year.

We reported revenues of approximately $179.3 million for the year ended June 30, 2012, down from approximately $201.7 million reported for the year ended June 30, 2011. This decrease in sales was principally attributable to lower equivalent production for the period as well as a lower average equivalent sales price received for the period.

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.

Average Sales Prices. For the fiscal year ended June 30, 2013, the price of natural gas was $3.56 per Mcf while the price for oil and NGLs was $107.75 per barrel and $0.86 per gallon, respectively. 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.

Operating Expenses. Lease operating expenses ("LOE") for the fiscal year ended June 30, 2013 were approximately $31.9 million, which included approximately $3.3 million of Louisiana state severance taxes, $12.0 million in workover costs for Vermilion 170, $0.4 million in workover costs for other wells and $4.7 million of well insurance. The remaining $11.4 million related to recurring lease operating expenses.

Operating expenses for the year ended June 30, 2012 were approximately $25.2 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 $25.7 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 recurring lease operating expenses for 11 offshore wells.

Exploration Expenses. We reported approximately $51.7 million of exploration expenses for the fiscal year ended June 30, 2013, which consists of $50.0 million for our dry holes at Ship Shoal 134 ("Eagle") and South Timbalier 75 ("Fang"), $1.4 million related to an unsuccessful drilling program at Jim Hogg County, Texas and $0.3 million for geological and geophysical activities, seismic data and delay rentals.

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

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization for the fiscal year ended June 30, 2013 was approximately $41.1 million. This compares to approximately $49.1 million for the year ended June 30,

2012. The decrease in depreciation, depletion and amortization was primarily attributable to a decrease in overall production.

Depreciation, depletion and amortization for the year ended June 30, 2012 was approximately $49.1 million. This compares to approximately $52.2 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.

Impairment of Natural Gas and Oil Properties. For the fiscal year ended June 30, 2013, the Company recorded impairment expense of approximately $14.8 million. Of this amount, approximately $12.0 million related to our Ship Shoal 263 well; $2.1 million related to the Eugene Island 24 platform and other properties, $0.5 million related to leasehold costs on our Ship Shoal 83 prospect which we relinquished in August 2013, and $0.2 million related to leasehold costs on our Brazos Area 543 prospect.

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.

General and Administrative Expenses. General and administrative expenses for the fiscal year ended June 30, 2013 were approximately $14.4 million, compared to $10.4 million for the year ended June 30, 2012. Major components of general and administrative expenses for the year ended June 30, 2013 included approximately $6.2 million in salaries and benefits, $1.2 million in office administration and other expenses, $0.6 million in board compensation, $0.6 million in accounting and tax services, $1.0 million in franchise taxes, and $4.8 million in legal, professional and other administrative expenses, which includes $3.0 million attributable to the proposed Merger.

General and administrative expenses for the year ended June 30, 2012 were approximately $10.4 million, compared to approximately $12.3 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 $12.3 million. 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.

Other Income (Expense). Other income for the fiscal year ended June 30, 2013 included the proceeds of a $10 million life insurance policy for the Company's former Chairman, President and Chief Executive Officer, Mr. Peak, who passed away on April 19, 2013.

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%, 0% and 5% of combined revenues for the fiscal year ended June 30, 2013, 2012 and 2011, 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 $95.7 million in cash for the year ended June 30, 2013 compared to $73.6 million for the same period in 2012. This increase in cash provided by operating activities was primarily attributable to the timing of payments of the Company's obligations.

Cash flow from operating activities provided approximately $73.6 million in cash for the year ended June 30, 2012 compared to $140.6 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 From Investing Activities. Cash used in investing activities for the fiscal year ended June 30, 2013 was approximately $88.7 million, which consisted mainly of $80.4 million in capital expenditures for drilling and developing wells ($50.0 million of this was Eagle and Fang), investing $16.4 million in Alta and Exaro, partially

offset by receiving $7.5 million as a return of capital related to our Exaro investment and $0.6 million as a distribution from REX to its partners.
Cash flows used in investing activities for the year ended June 30, 2012 were approximately $73.4 million, which consisted mainly of $20.8 million in capital expenditures for developing our wells and facilities and $53.4 million in equity

investments in Alta and Exaro. Cash flows used in investing activities for the year ended June 30, 2011 were approximately $33.3 million, which consisted mainly of $70.0 million in capital expenditures, offset by receiving approximately $38.7 million in proceeds from the sale of assets.

Cash From Financing Activities. Cash used in financing activities for the fiscal year ended June 30, 2013 were approximately $35.5 million, compared to $20.2 million used in financing activities for the same period in 2012. This increase in cash used is attributable to paying a $30.5 million dividend to shareholders in December 2012 and purchasing $5 million of common stock under our publicly announced share repurchase programs.

Cash used in financing activities for the year ended June 30, 2012 were approximately $20.2 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.

Income Taxes. During the year ended June 30, 2013 we paid $2.4 million in income taxes and received a federal refund of $4.9 million for prior year tax over-payments. During the year ended 2012 and 2011, we paid approximately $50.7 million and $31.9 million, respectively, in federal and state income taxes, net of refunds received.

Capital Budget. For fiscal year 2014, our capital expenditure budget calls for us to invest approximately $35.0 million from cash flow from operations and cash on hand as follows:

- We have budgeted to invest approximately $12.5 million to drill, complete and begin production on our South Timbalier 17 well.

- We have budgeted to invest approximately $22.5 million to drill our Ship Shoal 255 prospect. Should we be successful, 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.

On April 30, 2013, the Company announced that it had entered into a Merger Agreement with Crimson for an all-stock transaction pursuant to which Crimson would become a wholly-owned subsidiary of the Company. Should the Merger be approved by the Company's shareholders, we will have the opportunity to spend significantly more capital to develop Crimson's assets. See Note 16 - Merger with Crimson Exploration, Inc. for more information on the Merger.

Discontinued Operations. The Company, since its inception in September 1999, has raised money from various property sales. These sales brought 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. 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, 2012 and 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. The Company did not have any property sales for the fiscal year ended June 30, 2013.

Fiscal Year of Property Sale	Proceeds	Reserves	Reserves at end of	Standardized Measure of

	Received	Sold (Bcfe)	Fiscal Year (Bcfe)	Discounted Future Net Cash Flows at end of Fiscal Year ('000)
2012	$10 thousand	—	256.6	$513,932
2011	$38.7 million	17.2	296.7	$717,360

For fiscal year 2012 and 2011, the Company realized approximately $(0.4) million and $6.7 million in operating cash flows from discontinued operations, approximately $10,000 and $10.9 million in investing cash flows from discontinued operations and approximately $0.4 million and $(17.5) 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, 2013:

	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	1,302	318	636	348	—
Asset retirement obligations	13,345	623	—	—	12,722
Operating leases	871	328	543	—	—
Total	$15,518	$1,269	$1,179	$348	$12,722

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 $20.6 million in Exaro Energy.
Credit Facility
On October 2010, the Company completed the arrangement of a $40 million secured revolving credit agreement with Amegy Bank (the “Credit Agreement”). The Credit Agreement is supported by a hydrocarbon borrowing base and is 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. The evaluation of natural gas and oil leasehold acquisition costs included in unproved properties requires management's judgment of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

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.

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, 2013 of 5%, 10% and 15% would affect depreciation, depletion and amortization expense by approximately $2.1 million, $4.5 million, and $7.1 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 May 2013, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), revised its criteria related to internal controls over financial reporting from the originally established 1992 Internal Control - Integrated Framework with 2013 Internal Control - Integrated Framework. The modified framework provides enhanced guidance that ties control objectives to the related risk, enhancement of governance concepts, increased emphasis on globalization of markets and operations, increased recognition of use and reliance on information technology, increased discussion of fraud as it relates to internal control, changes of control deficiency descriptions, and that internal reporting is included in both financial and nonfinancial objectives. The revised framework is effective for interim and annual periods beginning after December 15, 2013, with early adoption being permitted. We are currently evaluating the provisions of the revised framework and assessing the impact, if any, it may have on our internal control structure.

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2013-04 Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (ASU 2013-04). ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. U.S. GAAP does not include specific guidance on accounting for such obligations with joint and several liability, which has resulted in diversity in practice. The accounting update is effective for interim and annual periods beginning after December 15, 2013. We are currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on our financial position and results of operations.

Item 7A. Quantitative and Qualitative Disclosure about Market Risk

Commodity Risk. Our major commodity price risk exposure is to the prices received for our natural gas and oil production. Realized commodity prices received for our production are tied to the spot prices applicable to natural gas and crude oil at the applicable delivery points. Prices received for natural gas and oil are volatile and unpredictable. We do not hedge against price risk exposure. For the year ended June 30, 2013, a 10% fluctuation in the prices received for natural gas and oil production would have had an approximately $12.7 million impact on our revenues.

Interest Rate Risk. As of the date of this report, we had no long-term debt subject to the risk of loss associated with movements in interest rates.

As of June 30, 2013, we had approximately $101.5 million in cash and cash equivalents, all of which was held in interest bearing investment accounts. Investments in fixed-rate, interest-earning instruments carry a degree of interest rate and credit rating risk. Fixed-rate securities may have their fair market value adversely impacted because of changes in interest rates and credit ratings. Additionally, the value of our investments may be impaired temporarily or permanently. Due in part to these factors, our investment income may decline and we may suffer losses in principal. Currently, we do not use any derivative or other financial instruments or derivative commodity instruments to hedge any market risks, including changes in interest rates or credit ratings, and we do not plan to employ these instruments in the future. Because of the nature of the issuers of the securities that we invest in, we do not believe that we have any cash flow exposure arising from changes in credit ratings. Based on a sensitivity analysis performed on the financial instruments held as of June 30, 2013, an immediate 10% change in interest rates is not expected to have a material effect on our near-term financial condition or results of operations.

Item 8. Financial Statements and Supplementary Data

The financial statements and supplemental information required to be filed under Item 8 of Form 10-K are presented on pages F-1 through F-29 of this Form 10-K.

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

An evaluation was performed under the supervision and with the participation of the Company’s senior management of the effectiveness of the Company’s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”)) as of June 30, 2013, the end of the period covered by this report. Based on that evaluation, the Company’s management, including the Chairman and Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer, concluded that the Company’s disclosure controls and procedures were effective as of such date to ensure that information required to be disclosed in the reports that the Company files under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and (ii) accumulated and communicated to the Company’s management, including the Chairman, Acting Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, as appropriate, to allow timely decisions regarding required disclosures.

Changes in Internal Control Over Financial Reporting

There was no change in our internal controls over financial reporting during the three months ended June 30, 2013 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management’s Report on Internal Control Over Financial Reporting

The Company’s management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company’s management, including the Chairman and Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in 1992 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the

Treadway Commission. Based on the Company's evaluation under the framework in 1992 Internal Control—Integrated Framework, the Company's management concluded that its internal control over financial reporting was effective as of June 30, 2013.

Grant Thornton LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has audited the effectiveness of our internal control over financial reporting as of June 30, 2013, as stated in their report which is included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders

Contango Oil & Gas Company

We have audited the internal control over financial reporting of Contango Oil & Gas Company's (a Delaware corporation) and subsidiaries (the "Company") as of June 30, 2013, based on criteria established in 1992 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Contango Oil & Gas Company maintained, in all material respects, effective internal control over financial reporting as of June 30, 2013, based on criteria established in 1992 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended June 30, 2013 and our report dated August 29, 2013 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Houston, Texas

August 29, 2013

Item 9B. Other Information

On November 29, 2012, the Board of the Company declared a special dividend of $2.00 per share of common stock which was paid on December 17, 2012 to each holder of record of the Company's common stock as of the close of business on December 10, 2012.

On September 30, 2008, the Company adopted a Stockholder Rights Plan (the “Plan”) which expired in September 30, 2011. The Plan was designed to ensure that all stockholders of Contango receive fair value for their shares of common stock in the event of any proposed takeover of Contango and to guard against the use of partial tender offers or other coercive tactics to gain control of Contango without offering fair value to all of Contango’s stockholders. The Plan was not intended, nor did it operate, to prevent an acquisition of Contango on terms that are favorable and fair to all stockholders. Upon expiration of the Plan, the Company did not adopt, and does not currently intend to adopt, a similar plan.

On April 29, 2013, the Company and Crimson entered into a Merger Agreement, pursuant to which Crimson will become a wholly owned subsidiary of the Company. Subject to the terms and conditions of the Merger Agreement, each share of Crimson common stock will be converted into 0.08288 shares of common stock of the Company. The Merger is intended to qualify as a tax-free reorganization for U.S. federal income tax purposes, so that none of the Company, Crimson or Crimson's stockholders will recognize any gain or loss in the Merger, except that Crimson's stockholders may recognize gain or loss with respect to cash received in lieu of fractional shares of Company common stock.

The closing of the Merger is expected to occur in early October 2013, subject to the satisfaction or waiver of certain customary conditions, including, among others, (i) the adoption of the Merger Agreement by Crimson's stockholders; (ii) the approval by the Company's stockholders of the issuance of Company common stock in the Merger to Crimson's stockholders; (iii) the approval for listing on the New York Stock Exchange of the Company common stock to be issued in the Merger; (iv) subject to specified materiality standards, the accuracy of the representations and warranties of, and the performance of all covenants by, the parties; (v) the absence of a material adverse effect with respect to each of Crimson and the Company; and (vi) the delivery of tax opinions that the Merger will be treated as a “reorganization” within the meaning of Section 368(a) of the Internal Revenue Code. See Note 16 - Merger with Crimson Exploration Inc. for additional information.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information regarding directors, executive officers, promoters and control persons required under Item 10 of Form 10-K will be contained in our Definitive Proxy Statement for our 2013 Annual Meeting of Stockholders (the “Proxy Statement”) under the headings “Election of Directors”, “Executive Compensation”, “Section 16(a) Beneficial Ownership Reporting Compliance” and “Corporate Governance” and is incorporated herein by reference. The Proxy Statement will be filed with the SEC pursuant to Regulation 14A of the Exchange Act, not later than 120 days after June 30, 2013.

Item 11. Executive Compensation

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

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

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

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

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

Item 14. Principal Accountant Fees and Services

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

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules:

The financial statements are set forth in pages F-1 to F-22 of this Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibits:

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

Exhibit Number	Description
2.1	Purchase and Sale Agreement, by and between Juneau Exploration, L.P. and REX Offshore Corporation, dated as of September 1, 2005. (10)
2.2	Purchase and Sale Agreement, by and between Juneau Exploration, L.P. and COE Offshore, LLC dated as of September 1, 2005. (10)
2.3	Agreement and Plan of Merger, among Contango Oil & Gas Company, Contango Acquisition, Inc. and Crimson Exploration Inc., dated as of April 29, 2013. (26)
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)
4.6	Registration Rights Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, OCM Crimson Holdings, LLC and OCM GW Holdings, LLC. (26)
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)

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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		Registration Rights Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, OCM Crimson Holdings, LLC and OCM GW Holdings, LLC. (26)
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. (25)
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. (25)
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. (25)
10.51		Participation Agreement covering OCS-G 33596, Vermilion 170, dated as of July 1, 2010 between Republic Exploration LLC and Contango Operators, Inc. (25)
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. (25)
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. (25)
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. (25)
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. (25)
10.56		Participation Agreement covering Tuscaloosa Marine Shale, dated as of August 27, 2012 between Juneau Exploration LP and Contango Operators, Inc. (25)
10.57		Letter Agreement dated as of June 8, 2012 between Juneau Exploration LP and Contango Operators, Inc. (25)
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. (25)
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. (25)
10.60		Agreement to Purchase Overriding Royalty Interest, dated March 1, 2010 between Contango Offshore Exploration LLC and Juneau Exploration LP. (25)
10.61		Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, Contango Acquisition, Inc. and OCM Crimson Holdings, LLC. (26)
10.62		Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, Contango Acquisition, Inc. and OCM GW Holdings, LLC. (26)
10.63		Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, Contango Acquisition, Inc. and Allan D. Keel. (26)

10.64	Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, Contango Acquisition, Inc. and E. Joseph Grady. (26)
10.65	Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, Contango Acquisition, Inc. and A. Carl Isaac. (26)
10.66	Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, Contango Acquisition, Inc. and Jay S. Mengle. (26)
10.67	Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, Contango Acquisition, Inc. and Thomas H. Atkins. (26)

10.68	Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company, Contango Acquisition, Inc. and John A. Thomas. (26)
10.69	Employment Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company and Allan D. Keel. (26)
10.70	Employment Agreement, dated as of April 29, 2013, among Contango Oil & Gas Company and E. Joseph Grady. (26)
10.71	Termination of Advisory Agreement between Contango Oil & Gas Company and Juneau Exploration, L.P., dated as of April 1, 2012. (27)
10.72	First Right of Refusal Agreement between Contango Oil & Gas Company and Juneau Exploration, L.P., entered into as of January 1, 2013. (27)
10.73	Advisory Agreement between Contaro Company and Juneau Exploration, L.P., entered into as of January 1, 2013. (27)
10.74	Employment Agreement, dated as of June 10, 2013, among Contango Oil & Gas Company and Jeffrey A. Sikora. (28)
10.75	Employment Agreement, dated as of June 7, 2013, among Contango Oil & Gas Company and A. Carl Isaac. (28)
10.76	Employment Agreement, dated as of June 7, 2013, among Contango Oil & Gas Company and John A. Thomas. (28)
10.77	Employment Agreement, dated as of June 7, 2013, among Contango Oil & Gas Company and Jay S. Mengle. (28)
10.78	Employment Agreement, dated as of June 7, 2013, among Contango Oil & Gas Company and Thomas H. Atkins. (28)
10.79	Transition Agreement, dated as of June 10, 2013, between Contango Oil & Gas Company and Marc Duncan. (29)
10.80	Participation Agreement covering Central Gulf of Mexico Lease Sale 227, dated as of March 21, 2013 between Republic Exploration LLC and Contango Operators, Inc. †
10.81	Participation Agreement covering Timbalier Island Prospect, South Timbalier Area Block 17, S.L. 21906, dated as of April 3, 2013 between Republic Exploration LLC, Juneau Exploration, L.P. and Contango Operators, Inc. †
14.1	Code of Ethics. (25)
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 W.D. Von Gonten & Co. †
23.4	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. †
99.2	Report of W.D. Von Gonten and Company †
99.3	Form of Support and Irrevocable Proxy Agreement, dated as of April 29, 2013, among Crimson Exploration Inc., and the following directors and executive officers of Contango Oil & Gas Company: the Estate of Kenneth R. Peak, Joseph J. Romano, Brad Juneau, Sergio Castro and Yaroslava Makalskaya.

(26)

† Filed herewith.

* Indicates a management contract or compensatory plan or arrangement.

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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.
25.

Filed as an exhibit to the Company’s report on Form 10-K for the fiscal year ended June 30, 2012, as filed with the Securities and Exchange Commission on August 29, 2012.

26. Filed as an exhibit to the Company’s report on Form 8-K, dated as of April 29, 2013, as filed with the Securities and Exchange Commission on May 1, 2013.

27. Filed as an exhibit to the Company's report on Form 10-Q for the quarter ended December 31, 2012, as filed with the Securities and Exchange Commission on February 11, 2013.

28. Filed as an exhibit to the Company's Registration Statement on Form S-4, as filed with the Securities and Exchange Commission on June 13, 2013.

29. Filed as an exhibit to the Company's report on Form 8-K, dated as of June 7, 2013, as filed with the Securities and Exchange Commission on June 14, 2013.

SIGNATURES

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

CONTANGO OIL & GAS COMPANY

/s/ JOSEPH J. ROMANO	/s/ SERGIO CASTRO	/s/ YAROSLAVA MAKALSKAYA
Joseph J. Romano	Sergio Castro	Yaroslava Makalskaya
Chief Executive Officer	Chief Financial Officer	Chief Accounting Officer
(principal executive officer)	(principal financial officer)	(principal accounting officer)

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

Name	Title	Date
/s/ B.A. BERILGEN B.A. Berilgen	Director	August 29, 2013
/s/ JAY D. BREHMER Jay D. Brehmer	Director	August 29, 2013
/s/ BRAD. JUNEAU Brad Juneau	Director	August 29, 2013
/s/ CHARLES M. REIMER Charles M. Reimer	Director	August 29, 2013
/s/ STEVEN L. SCHOONOVER Steven L. Schoonover	Director	August 29, 2013

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Contango Oil & Gas Company

We have audited the accompanying consolidated balance sheets of Contango Oil & Gas Company (a Delaware corporation) and subsidiaries (the "Company") as of June 30, 2013 and 2012, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the three years in the period ended June 30, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Contango Oil & Gas Company and subsidiaries as of June 30, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended June 30, 2013 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of June 30, 2013, based on criteria established in 1992 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated August 29, 2013 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Houston, Texas
August 29, 2013

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	June 30, 2013	2012
CURRENT ASSETS:	(thousands)	
Cash and cash equivalents	$101,485	$129,983
Accounts receivable:		
Trade receivable	26,312	29,688
Joint interest billings	4,996	4,768
Income taxes	4,504	4,510
Other receivables	648	242
Prepaid expenses	4,146	5,762
Inventory and other	2,147	260
Total current assets	144,238	175,213
PROPERTY, PLANT AND EQUIPMENT:		
Natural gas and oil properties, successful efforts method of accounting:		
Proved properties	562,572	561,713
Unproved properties	24,259	12,485
Furniture and equipment	229	213
Accumulated depreciation, depletion and amortization	(218,122)	(178,081)
Total property, plant and equipment, net	368,938	396,330
OTHER ASSETS:		
Investment in affiliates	63,123	52,827
Other	162	284
TOTAL ASSETS	$576,461	$624,654
CURRENT LIABILITIES:		
Accounts payable	$4,926	$3,084
Royalties and revenue payable	21,651	22,098
Accrued liabilities	4,882	6,796
Accrued exploration and development	313	2,334
Total current liabilities	31,772	34,312
DEFERRED TAX LIABILITY	115,923	118,010
ASSET RETIREMENT OBLIGATION	9,612	7,993
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
SHAREHOLDERS' EQUITY:		
Common stock, $0.04 par value, 50 million shares authorized, 20,135,107 shares issued and 15,194,952 shares outstanding at June 30, 2013, 20,135,107 shares issued and 15,292,448 shares outstanding at June 30, 2012	805	805
Additional paid-in capital	79,024	79,024
Treasury stock at cost (4,940,155 shares at June 30, 2013 and 4,842,659 shares at June 30, 2012)	(117,162)	(112,207)
Retained earnings	456,487	496,717
Total shareholders' equity	419,154	464,339
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$576,461	$624,654

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

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

	Year Ended June 30, 2013	2012	2011
REVENUES:			
Natural gas and oil sales	$127,201	$179,272	$201,721
Total revenues	127,201	179,272	201,721
EXPENSES:			
Operating expenses	31,907	25,183	25,691
Exploration expenses	51,748	346	9,751
Depreciation, depletion and amortization	41,060	49,052	52,198
Impairment of natural gas and oil properties	14,845	—	1,786
General and administrative expense	14,364	10,418	12,341
Total expenses	153,924	84,999	101,767
Gain (loss) from investment in affiliates (net of income taxes)	1,241	(449)	—
Other income (expense)	9,665	(312)	(157)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(15,817)	93,512	99,797
Benefit (provision) for income taxes	6,097	(34,299)	(35,338)
NET INCOME (LOSS) FROM CONTINUING OPERATIONS	(9,720)	59,213	64,459
DISCONTINUED OPERATIONS (NOTE 5)			
Discontinued operations, net of income taxes	—	(824)	574
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCK	$(9,720)	$58,389	$65,033
NET INCOME (LOSS) PER SHARE:			
Basic			
Continuing operations	$(0.64)	$3.84	$4.11
Discontinued operations	—	(0.05)	0.04
Total	$(0.64)	$3.79	$4.15
Diluted			
Continuing operations	$(0.64)	$3.84	$4.10
Discontinued operations	—	(0.05)	0.04
Total	$(0.64)	$3.79	$4.14
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	15,221	15,423	15,665
Diluted	15,221	15,425	15,713

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

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

	Year Ended June 30,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES:			
Income (loss) from continuing operations	$(9,720)	$59,213	$64,459
Plus income (loss) from discontinued operations, net of income taxes	—	(824)	574
Net income	(9,720)	58,389	65,033
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	41,060	49,052	59,337
Impairment of natural gas and oil properties	14,845	1,031	2,315
Exploration expenses	51,350	—	9,657
Deferred income taxes	(2,087)	(5,716)	(7,819)
Loss (gain) on sale of assets	—	169	(1,813)
Loss (gain) from investment in affiliates	(1,910)	690	—
Stock-based compensation	—	3	1,276
Tax benefit from exercise of stock options	—	(254)	(502)
Changes in operating assets and liabilities:			
Decrease (increase) in accounts receivable and other	2,969	14,280	(2,029)
Decrease (increase) in inventory	(1,887)	—	—
Decrease (increase) in prepaids and other receivables	1,894	(1,840)	1,671
Increase (decrease) in accounts payable and advances from joint owners	1,166	(27,842)	(5,718)
Increase (decrease) in other accrued liabilities	(1,914)	(3,413)	7,142
Increase (decrease) in income taxes payable, net	5	(11,357)	11,917
Other	(116)	379	91
Net cash provided by operating activities	95,655	73,571	140,558
CASH FLOWS FROM INVESTING ACTIVITIES:			
Natural gas and oil exploration and development expenditures	(80,418)	(20,847)	(69,993)
Advance under note receivable	—	(500)	—
Repayment of note receivable	—	500	2,028
Investments in affiliates	(16,416)	(53,406)	(3,959)
Distributions from affiliates	8,146	823	—
Proceeds from the sale of assets	—	—	38,671
Net cash used in investing activities	(88,688)	(73,430)	(33,253)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Dividends	(30,510)	—	(6)
Purchase of common stock	(4,955)	(20,419)	(9,769)
Tax benefit from exercise/cancellation of stock options	—	254	502
Debt issuance costs	—	—	(494)
Net cash used in financing activities	(35,465)	(20,165)	(9,767)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(28,498)	(20,024)	97,538
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	129,983	150,007	52,469
CASH AND CASH EQUIVALENTS, END OF PERIOD	$101,485	$129,983	$150,007

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid (received) for taxes, net	$(2,453)	$50,687	$31,876
Cash paid for interest	$50	$121	$60

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

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total Shareholders' Equity
Balance at June 30, 2010	15,684	$799	$77,968	$(82,019)	$380,582	$377,330
Exercise of stock options	153	6	(6)	—	—	—
Tax benefit from exercise of stock options	—	—	502	—	—	502
Treasury shares at cost	(173)	—	—	(9,769)	—	(9,769)
Stock option expense	—	—	814	—	—	814
Dividends	—	—	—	—	(7,287)	(7,287)
Net income	—	—	—	—	65,033	65,033
Balance at June 30, 2011	15,664	$805	$79,278	$(91,788)	$438,328	$426,623
Tax benefit from exercise of stock options	—	—	(254)	—	—	(254)
Treasury shares at cost	(372)	—	—	(20,419)	—	(20,419)
Net income	—	—	—	—	58,389	58,389
Balance at June 30, 2012	15,292	$805	$79,024	$(112,207)	$496,717	$464,339
Treasury shares at cost	(97)	—	—	(4,955)	—	(4,955)
Dividends	—	—	—	—	(30,510)	(30,510)
Net loss	—	—	—	—	$(9,720)	(9,720)
Balance at June 30, 2013	15,195	$805	$79,024	$(117,162)	$456,487	$419,154

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

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

1. Organization and Business

Contango Oil & Gas Company (collectively with its subsidiaries, “Contango” or the “Company”) is a Houston-based, independent natural gas and oil company. The Company’s business is to explore, develop, produce and acquire natural gas and oil properties primarily offshore in the Gulf of Mexico in water-depths of less than 300 feet. Contango Operators, Inc. (“COI”), our wholly-owned subsidiary, acts as operator of our offshore properties. Contango has additional onshore investments in i) Alta Resources Investments, LLC, whose primary area of focus is the liquids-rich Kaybob Duvernay in Alberta, Canada; ii) Exaro Energy III LLC, which is primarily focused on the development of proved natural gas reserves in the Jonah Field in Wyoming; and iii) the Tuscaloosa Marine Shale where we own approximately 24,000 acres.

On April 19, 2013, the Company's founder and former Chairman, President and Chief Executive Officer, Mr. Kenneth R. Peak, passed away at the age of 67. The Company held a $10 million life insurance policy for Mr. Peak and received the proceeds of such policy in early May 2013.

On April 30, 2013, the Company announced that it had signed a merger agreement (the "Merger Agreement") with Crimson Exploration Inc. ("Crimson"), for an all-stock transaction pursuant to which Crimson will become a wholly owned subsidiary of Contango (the "Merger"). Upon consummation of the merger, each share of Crimson stock will be converted into 0.08288 shares of Contango stock resulting in Crimson stockholders owning 20.3% of the post-merger Contango. This transaction is subject to shareholder approval of both Contango and Crimson and is expected to close by October 2013, subject to satisfaction of a number of closing conditions. See Note 16 - Merger with Crimson Exploration, Inc. for additional information.

2. Summary of Significant Accounting Policies

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

Other Investments. Contango’s 19.5% ownership of Moblize Inc. (“Moblize”) and 2.0% ownership of Alta Energy Canada Partnership are accounted for using the cost method. Under the cost method, Contango records an investment in the stock of an investee at cost, and recognizes dividends received as income. Dividends received in excess of earnings subsequent to the date of investment are considered a return of investment and are recorded as reductions of cost of the investment.

The Company has two seats on the board of directors of Exaro Energy III LLC ("Exaro") and has significant influence, but not control, over the company. As a result, the Company's 37% ownership in Exaro is accounted for using the equity method. Under the equity method, the Company's proportionate share of Exaro's net income increases our investment in our consolidated balance sheet, while a net loss or payment of dividends decreases our investment. In our consolidated statement of operations, our proportionate share of Exaro's net income or loss is reported as a single-line item. For the fiscal year ended June 30, 2013, the Company recorded a gain from affiliates related to our Exaro investment of approximately $1.2 million, net of taxes. See Note 7 - Investment in Exaro Energy III LLC.

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

Revenue Recognition. Revenues from the sale of natural gas and oil produced are recognized upon the passage of title, net of royalties. Revenues from natural gas production are recorded using the sales method. When sales volumes exceed the Company's entitled share, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds the Company's share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. As of June 30, 2013 and 2012, the Company had no significant imbalances.

Cash Equivalents. Cash equivalents are considered to be highly liquid investment grade debt investments having an original maturity of 90 days or less. As of June 30, 2013, the Company had approximately $101.5 million in cash and cash equivalents, all of which was held in interest bearing investment accounts.

Accounts Receivable. The Company sells natural gas and crude oil to a limited number of customers. In addition, the Company participates with other parties in the operation of natural gas and crude oil wells. Substantially all of the Company’s accounts receivables are due from either purchasers of natural gas and crude oil or participants in natural gas and crude oil wells for which the Company serves as the operator. Generally, operators of natural gas and crude oil properties have the right to offset future revenues against unpaid charges related to operated wells.
The allowance for doubtful accounts is an estimate of the losses in the Company’s accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Amounts deemed uncollectible are charged to the allowance.
Accounts receivable allowance for bad debt was $0 at June 30, 2013 and 2012. At June 30, 2013 and 2012, the carrying value of the Company’s accounts receivable approximated fair value.
Successful Efforts Method of Accounting. The Company follows the successful efforts method of accounting for its natural gas and oil activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs, such as seismic costs and other geological and geophysical expenses, are expensed as incurred. Depreciation, depletion and amortization is calculated on a field by field basis using the unit of production method, with lease acquisition costs amortized over total proved reserves and other capitalized costs amortized over proved developed reserves.
Impairment of Long-Lived Assets. When circumstances indicate that proved properties may be impaired, the Company compares expected undiscounted future cash flows on a field by field basis to the unamortized capitalized cost of the asset. If the estimated future undiscounted cash flows, based on the Company’s estimate of future reserves, natural gas and oil prices and operating costs and anticipated production levels from oil and natural gas reserves, are lower than the unamortized capitalized cost, then the capitalized cost is reduced to its fair value. For the fiscal year ended June 30, 2013, we recorded an impairment expense of approximately $14.8 million related to proved properties. Of this amount, approximately $12.0 million related to our Ship Shoal 263 well, $2.1 million related to the Eugene Island 24 platform and other properties, and $0.5 million related to leasehold costs on our Ship Shoal 83 prospect which we intend to relinquish by October 2013, and $0.2 million related to leasehold costs on our Brazos Area 543 prospect which we intend to relinquish by March 2014. Despite the writedown of Ship Shoal 263, this well reached payout during fiscal year 2012. The Company did not recognize impairment of proved properties for the fiscal years ended June 30, 2012 or 2011.

Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, and any such impairment is charged to expense in the period. The Company did not recognize any impairment of unproven properties for the year ended June 30, 2013 or 2012. For the year ended June 30, 2011, the Company recorded impairment expense of approximately $1.8 million, related to the relinquishment of 14 unproved lease blocks owned by Republic Exploration, LLC ("REX") and Contango Offshore Exploration, LLC (“COE”).
Net Income per Common Share. Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. See Note 6 – Net Income (Loss) Per Common Share for the calculations of basic and diluted net income per common share.

Income Taxes. The Company follows the liability method of accounting for income taxes under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements and (ii) operating loss and tax credit carryforwards for tax purposes. Deferred tax assets are reduced by a valuation allowance when, based upon management’s estimates, it is more likely than not that a portion of the deferred tax assets will not be realized in a future period. The Company reviews its tax positions quarterly for tax uncertainties. The Company did not have significant uncertain tax positions as of June 30, 2013. The amount of unrecognized tax benefits did not materially change from June 30, 2012. The amount of unrecognized tax benefits may change in the next twelve months; however, we do not expect the change to have a significant impact on our financial position or results of operations. The Company includes interest and penalties in interest income and general and administrative expenses, respectively, in its statement of operations.

The Company files income tax returns in the United States and various state jurisdictions. The Company's federal tax returns for 2009 – 2013, and state tax returns for 2008 - 2013, remain open for examination by the taxing authorities in the respective jurisdictions where those returns were filed.

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

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

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

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

Inventory. Inventory primarily consists of casing and tubing for the drilling of wells. Also included in inventory are items for the repair and maintenance of equipment used on wells and facilities that the Company operates. Inventory is recorded at the lower of cost or market on the specific identification method.

Derivative Instruments and Hedging Activities. The Company did not enter into any derivative instruments or hedging activities for the fiscal years ended June 30, 2013, 2012 or 2011, nor did we have any open commodity derivative contracts at June 30, 2013 or 2012.

Reclassifications. Certain reclassifications have been made to the fiscal year 2012 and 2011 amounts in order to conform to the 2013 presentation. These reclassifications were not material.

Recent Accounting Pronouncements. In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), revised its criteria related to internal controls over financial reporting from the originally established 1992 Internal Control - Integrated Framework with 2013 Internal Control - Integrated Framework. The modified framework provides enhanced guidance that ties control objectives to the related risk, enhancement of governance concepts, increased emphasis on globalization of markets and operations, increased recognition of use and reliance on information technology, increased discussion of fraud as it relates to internal control, changes of control deficiency descriptions, and that internal reporting is included in both financial and nonfinancial objectives. The revised framework is effective for interim and annual periods beginning after December 15, 2013, with early adoption being permitted. We are currently evaluating the provisions of the revised framework and assessing the impact, if any, it may have on our internal control structure.

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2013-04 Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (ASU 2013-04). ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. U.S. GAAP does not include specific guidance on accounting for such obligations with joint and several liability, which has resulted in diversity in practice. The accounting update is effective for interim and annual periods beginning after December 15, 2013. We are currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on our financial position and results of operations.

3. Natural Gas and Oil Exploration and Production Risk

The Company's future financial condition and results of operations will depend upon prices received for its natural gas and oil production and the cost of finding, acquiring, developing and producing reserves.

Substantially all of its production is sold under various terms and arrangements at prevailing market prices. Prices for natural gas and oil are subject to fluctuations in response to changes in supply, market uncertainty and a variety of other factors beyond the Company's control.

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

4. Concentration of Credit Risk

The customer base for the Company is concentrated in the natural gas and oil industry. Major purchasers of our natural gas, oil and natural gas liquids for the fiscal year ended June 30, 2013 were ConocoPhillips Company (53%), Shell Trading US Company (21%), Enterprise Products Operating LLC (9%), ExxonMobil Oil Corp. (8%). Our sales to these companies are not secured with letters of credit and in the event of non-payment, we could lose up to two months of revenues. The loss of two months of revenues would have a material adverse effect on our financial position. There are numerous other potential purchasers of our production.

5. 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 reserves. B.A. Berilgen, a member of the Company's board of directors, was the Chief Executive Officer of Patara at the time. In May 2011, the Company sold to Patara its 90% working 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 16,700 Mmcfe, 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. The summarized financial results for the joint venture assets for the periods ended June 30, 2012 and 2011 are as follows:

	June 30, 2012	2011
	(thousands)	
Revenues	$—	$8,055
Operating expenses	(40)	(1,613)
Depletion expenses	—	(4,106)
Impairment and other expenses	—	(527)
Loss on sale	—	(651)
Income (loss) before income taxes	$(40)	$1,158
Benefit (provision) for income taxes	14	(618)
Income (loss) from discontinued operations, net of income taxes	$(26)	540

Rexer Assets

In May 2011, the Company sold to Patara its (i) 100% working interest (72.5% net revenue interest) in Rexer #1 drilled in south Texas; and (ii) 75% working interest (54.4% net revenue interest) in Rexer-Tusa #2 for approximately $2.5 million and recognized a pre-tax loss of approximately $0.3 million. The Rexer #1 well had proved reserves of approximately 0.5 Bcfe, net to Contango, while the Rexer-Tusa #2 had not been spud at the time of sale.

In October 2011, the Company sold its remaining 25% working interest (18.4% net revenue interest) in Rexer-Tusa #2 for $10,000 to Patara. The Company has accounted for the sale of the Rexer #1 and Rexer-Tusa #2 as discontinued operations as of June 30, 2012 and has included the results of these operations as discontinued operations for all periods presented. The summarized financial results for these Rexer assets for the periods ended June 30, 2012 and 2011 are as follows:

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
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	June 30, 2012 (thousands)	2011
Revenues	$6	$2,056
Operating expenses	(16)	(298)
Depletion expenses	(11)	(3,033)
Impairment of natural gas and oil properties	(1,031)	—
Exploration expenses	(7)	—
Loss on sale	(169)	$(273)
Loss before income taxes	$(1,228)	$(1,548)
Benefit for income taxes	430	542
Loss from discontinued operations, net of income taxes	$(798)	$(1,006)

Contango Mining Company

On September 29, 2010, Contango ORE, Inc. ("CORE"), then a wholly-owned subsidiary of the Company, filed with the Securities and Exchange Commission a Registration Statement on Form 10 which became effective November 29, 2010. Following the effective date, CORE acquired the assets and assumed the liabilities of Contango Mining Company ("Contango Mining"), another wholly-owned subsidiary of the Company. Additionally, subsequent to the effective date, the Company contributed $3.5 million of cash to CORE. In exchange, CORE issued 1,566,367 shares of its common stock to the Company in addition to the 100 shares which the Company held prior to that date. The Company distributed all its shares of CORE, valued at approximately $7.3 million, to its stockholders of record as of October 15, 2010 on the basis of one share of common stock of CORE for each ten shares of the Company's common stock then outstanding. In addition to the distribution of shares of CORE, the Company paid $6,213 in cash to its stockholders of record in exchange for partial shares. As of June 30, 2013 and 2012, the assets and liabilities of Contango Mining were excluded from the Company's financial statements.

Results of operations of Contango Mining for the fiscal year ended June 30, 2011 and for each of the previous periods are included in discontinued operations in the Company's Statement of Operations. No income or expense related to CORE were recognized for the year ended June 30, 2012 or 2013. The summarized financial results for Contango Mining for the fiscal year ended June 30, 2011 was as follows:

	June 30, 2011 (thousands)
Revenues	$—
Exploration expenses	(983)
General and administrative expenses	(154)
Gain on sale	2,737
Income before income taxes	$1,600
Benefit (provision) for income taxes	(560)
Income from discontinued operations, net of income taxes	$1,040

The gain on sale of discontinued operations for 2011 represents the difference between $7.3 million, the fair value of the shares of CORE distributed to the Company's shareholders, and the historical value of the assets and liabilities transferred to CORE on or subsequent to November 29, 2010.

6. Net Income (Loss) Per Common Share

A reconciliation of the components of basic and diluted net income per common share for the fiscal years ended June 30, 2013, 2012 and 2011 is presented below:

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (continued)

	Year Ended June 30, 2013		
(thousands, except per share amounts)	Net Loss	Shares	Per Share
Basic Earnings per Share:			
Net loss attributable to common stock	$(9,720)	15,221	$(0.64)
Diluted Earnings per Share:			
Net loss attributable to common stock	$(9,720)	15,221	$(0.64)

	Year Ended June 30, 2012		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Income from continuing operations	$59,213	15,423	$3.84
Discontinued operations, net of income taxes	(824)	15,423	(0.05)
Basic Earnings per Share:			
Net income attributable to common stock	$58,389	15,423	$3.79
Effect of potential dilutive securities:			
Stock options, net of shares assumed purchased	—	2	
Income from continuing operations	$59,213	15,425	$3.84
Discontinued operations, net of income taxes	(824)	15,425	(0.05)
Diluted Earnings per Share:			
Net income attributable to common stock	$58,389	15,425	$3.79

	Year Ended June 30, 2011		
(thousands, except per share amounts)	Net Income	Shares	Per Share
Income from continuing operations	$64,459	15,665	$4.11
Discontinued operations, net of income taxes	574	15,665	0.04
Basic Earnings per Share:			
Net income attributable to common stock	$65,033	15,665	$4.15
Effect of potential dilutive securities:			
Stock options, net of shares assumed purchased	—	48	
Income from continuing operations	$64,459	15,713	$4.10
Discontinued operations, net of income taxes	574	15,713	0.04
Diluted Earnings per Share:			
Net income attributable to common stock	$65,033	15,713	$4.14

7. Investment in Exaro Energy III LLC

In April 2012, the Company announced that through its wholly-owned subsidiary, Contaro Company, it had entered into a Limited Liability Company Agreement (the "LLC Agreement") in connection with the formation of Exaro Energy III LLC ("Exaro"). Pursuant to the LLC Agreement, as amended, the Company has committed to invest up to $67.5 million in cash in Exaro, together with other parties for an aggregate commitment of $182.5 million, or a 37% ownership interest in Exaro. As of June 30, 2013, the Company had invested approximately $46.9 million in Exaro, including $13.1 million that was invested during the fiscal year ended June 30, 2013.

The following table presents condensed balance sheet data for Exaro as of June 30, 2013 and 2012. The balance sheet data was derived from the Exaro balance sheet as of June 30, 2013 and June 30, 2012 and was not adjusted to represent our percentage of ownership interest in Exaro. Our share in the equity of Exaro is at June 30, 2013 is approximately $48 million.

	June 30, 2013	2012
Current assets	$ 24,038	$ 43,607
Non-current assets:		
Net property and equipment	128,147	2,125
Restricted cash escrow account	40,022	40,004
Other non-current assets	3,684	5,540
Total non-current assets	171,853	47,669
Total assets	$ 195,891	$ 91,276
Current liabilities	$ 19,107	$ 303
Non-current liabilities:		
Long-term debt	45,000	—
Other non-current liabilities	824	—
Total non-current liabilities	45,824	—
Member's equity	130,960	90,973
Total liabilities & member's equity	$ 195,891	$ 91,276

The following table presents the condensed results of operations for Exaro for the fiscal years ended June 30, 2013, and for the period from the inception of Exaro, March 19, 2012, to June 30, 2012. The results of operations for the fiscal year ended June 30, 2013 were derived by adding Exaro's statement of operations for the twelve months ended December 31, 2012 to its statement of operations for the six months ended June 30, 2013 and then subtracting its statement of operations for the period from inception to June 30, 2012. The income statement data below was not adjusted to represent our ownership interest but rather reflects the results of Exaro as a Company. Our share in Exaro's results of operations for the year ended June 30, 2013 and June 30, 2012 was $1.2 million, net of tax expense of $(0.7) million, and $(0.4) million, net of tax benefit of $0.2 million, respectively.

	Year Ended June 30, 2013	2012
Oil and natural gas sales	$ 27,932	$ 68
Other loss	(2,720)	—
Less:		
Lease operating expenses	8,157	23
Depreciation, depletion, amortization & accretion	8,178	—
General & administrative expense	3,227	1,536
Income/(loss) from continuing operations	5,650	(1,491)
Net interest income/(expense)	(604)	9
Net income (loss)	$ 5,046	$ (1,482)

Included in Other losses are realized and unrealized losses attributable to derivatives, whose value is likely to change based on future oil and gas prices. Exaro's results of operations do not include income taxes, because Exaro is treated as a partnership for tax purposes.

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
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8. Income Taxes

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

	Year Ended June 30, 2013 (thousands)		2012		2011	
Provision/(benefit) at statutory tax rate	$(5,302)	(0.35)%	$32,644	35.00%	$34,929	35.00%
State income tax provision, net of federal benefit	2,293	15.13%	1,712	1.84%	2,985	3.04%
Permanent differences	(2,424)	(16.00)%	(746)	(0.80)%	(2,678)	(2.73)%
Other	4	0.03%	447	0.48%	102	0.10%
Income tax provision /(benefit)	$(5,429)	(35.84)%	$34,057	36.52%	$35,338	35.41%

Included in permanent differences for the fiscal year ended June 30, 2013, is $10 million in proceeds from life insurance, offset by $3 million in non-deductible expenses related to the Merger. Included in permanent differences for the fiscal year ended June 30, 2011, is the IRC Section 199 benefit.

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

	Year Ended June 30, 2013 (thousands)	2012	2011
Current:			
Federal	$(5,306)	$36,824	$34,256
State	3,358	2,783	3,502
Total	$(1,948)	$39,607	$37,758
Deferred:			
Federal	$(3,669)	$(5,369)	$(1,405)
State	188	(181)	(1,015)
Total	$(3,481)	$(5,550)	$(2,420)
Total:			
Federal	$(8,975)	$31,455	$32,851
State	3,546	2,602	2,487
Total	$(5,429)	$34,057	$35,338

Of the total tax provision for the fiscal year ended June 30, 2013 and 2012, approximately $668,000 and $(241,000) of deferred income tax expense (benefit) are included in the gain/(loss) from affiliates line item in the Company's Consolidated Statement of Operations.

The net deferred tax liability is comprised of the following:

CONTANGO OIL & GAS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (continued)

	Year Ended June 30,		
	2013	2012	2011
Deferred tax liability:	(thousands)		
Temporary basis differences in natural gas and oil properties and other	$(115,923)	$(118,010)	$(123,472)
Net deferred tax liability	$(115,923)	$(118,010)	$(123,472)

9. Long-Term Debt

On October 22, 2010, the Company completed the arrangement of a secured revolving credit agreement with Amegy Bank (the "Credit Agreement") to replace its expiring credit agreement with BBVA Compass Bank. The Credit Agreement currently has a $40 million hydrocarbon borrowing base and is available to fund the Company's exploration and development activities, as well as repurchase shares of common stock, pay dividends, and fund working capital as needed. The Credit Agreement is secured by substantially all of the assets of the Company. Borrowings under the Credit Agreement bear interest at LIBOR plus 2.5%, subject to a LIBOR floor of 0.75%. The principal is due October 1, 2014, and may be prepaid at any time with no prepayment penalty. An arrangement fee of $300,000 was paid in connection with the facility and a commitment fee of 0.125% is owed on unused borrowing capacity. The Credit Agreement contains customary covenants including limitations on our current ratio and additional indebtedness. As of June 30, 2013 and 2012, the Company was in compliance with all covenants and had no amounts outstanding under the Credit Agreement.

10. Commitments and Contingencies

Contango pays delay rentals on its offshore leases and leases its office space and certain other equipment. In November 2010, the Company expanded its office space and extended its office lease agreement through February 29, 2016. As of June 30, 2013, minimum future lease payments for delay rentals and operating leases for our fiscal years are as follows:

Fiscal years ending June 30,	
	(thousands)
2014	$646
2015	642
2016	537
2017	278
2018 and thereafter	70
Total	$2,173

The amount incurred under operating leases and delay rentals during the years ended June 30, 2013, 2012 and 2011 was approximately $645,000, $423,000 and $288,000, respectively. As of June 30, 2013, we have committed to invest an additional $20.6 million with Exaro Energy III, LLC to develop onshore natural gas assets.

In July 2012, the Company granted year-end bonuses to employees and certain consultants. A portion of these bonuses have already been paid, with the remainder to vest and be paid on June 30, 2014, to incentivize the individuals to remain with the Company. As of June 30, 2013, approximately $230,000 of compensation remained to be vested, which will vest and be paid on June 30, 2014, as long as the employees are employed by the Company on the vesting date.

In conjunction with the potential merger with Crimson (See Note 16 - Merger with Crimson Exploration, Inc.), certain employees will not remain with the Company should the merger be approved by the Company's shareholders. The Company has entered into agreements with these individuals and has committed to pay a total of approximately $0.4 million in severance payments.

Litigation Related to the Merger

Several class action lawsuits have been brought by Crimson stockholders challenging the proposed merger and seeking, among other things, injunctive relief to enjoin the defendants from completing the merger on the agreed-upon terms, compensatory damages, and costs and disbursements relating to the lawsuits. Various combinations of

Crimson, Contango, members of Crimson's board of directors, and members of Crimson management have been named as defendants in these lawsuits. It is possible that additional, similar lawsuits may be filed.

The known plaintiffs in these lawsuits, based on the most current information provided by Crimson, collectively own a very small percentage of the total outstanding shares of Crimson common stock. The lawsuits allege, among other things, that Crimson's board of directors failed to take steps to obtain a fair price, failed to properly value Crimson, failed to protect against alleged conflicts of interest, failed to conduct a reasonably informed evaluation of whether the transaction was in the best interests of stockholders, failed to fully disclose all material information to stockholders, acted in bad faith and for improper motives, engaged in self-dealing, discouraged other strategic alternatives, took steps to avoid competitive bidding, and agreed to allegedly unreasonable deal protection mechanisms, including the no-shop and fiduciary-out provisions and termination fee. The lawsuits seek damages and injunctive relief. The lawsuits also allege that Contango aided and abetted the other defendants in violating duties to the Crimson stockholders.

Contango and Crimson believe that these lawsuits are without merit and intend to contest them vigorously.

11. Asset Retirement Obligation

The Company accounts for its retirement obligation of long lived assets by recording the net present value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. When the liability is initially recorded, a company increases the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. Activities related to the Company's ARO during the year ended June 30, 2013 and 2012 were as follows:

	Year Ended June 30,	
	2013	2012
	(thousands)	
Balance as of July 1	$7,993	$8,611
Liabilities incurred during period	2,023	53
Liabilities settled during period	(2,037)	(238)
Accretion	491	507
Change in estimate	1,142	(940)
Balance as of June 30	$9,612	$7,993

12. Stock Based Compensation

The Company's 1999 Stock Incentive Plan (the "1999 Plan") expired in August 2009. There are no outstanding options issued under the 1999 Plan.

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

Stock Options.

Under the 2009 Plan, the Company may issue up to 1,500,000 shares of common stock with an exercise price of each option equal to or greater than the market price of the Company's common stock on the date of grant. The Company may grant key employees both incentive stock options intended to qualify under Section 422 of the Internal Revenue Code of 1986, as amended, and stock options that are not qualified as incentive stock options. Stock option grants to non-employees, such as directors and consultants, can only be stock options that are not qualified as incentive stock options. Options generally expire after 5 or 10 years. The vesting schedule varies, and can vest over a 2, 3 or 4-year period. As of June 30, 2013, there were no options outstanding under the 2009 Plan.

A summary of the status of stock options granted under the 1999 Plan and 2009 Plan as of June 30, 2013, 2012 and 2011, and changes during the fiscal years then ended, is presented in the table

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below:

	Year Ended June 30,					
	2013		2012		2011	
	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price	Shares Under Options	Weighted Average Exercise Price
Outstanding, beginning of year	—	—	45,000	$54.21	305,334	$28.61
Granted	—	—	—	$—	—	$—
Exercised	—	—	—	$—	(152,544)	$21.38
Forfeited (1)	—	—	(45,000)	$54.21	(107,790)	$28.14
Outstanding, end of year	—	—	—	$—	45,000	$54.21
Aggregate intrinsic value ($000)	$—		$—		$190	
Exercisable, end of year	—	—	—	$—	45,000	$54.21
Aggregate intrinsic value ($000)	$—		$—		$190	
Available for grant, end of year	1,475,000		1,475,000		1,475,000	
Weighted average fair value of options granted during the year	$—		$—		$—	

(1) For the fiscal year ended June 30, 2012, forfeited options consist of options that were net-settled for cash with the Company. For the fiscal year ended June 30, 2011, forfeited options relate to options surrendered under a cashless exercise, with immediate sale to the Company.

Under the fair value method of accounting for stock options, cash flows from the exercise of stock options resulting from tax benefits in excess of recognized cumulative compensation cost (excess tax benefits) are classified as financing cash flows. For the fiscal years ended June 30, 2012 and 2011, approximately $0.3 million and $0.5 million, respectively, of such excess tax benefits were classified as financing cash flows. See Note 2 – Summary of Significant Accounting Policies.

Compensation expense related to employee stock option grants are recognized over the stock option's vesting period based on the fair value at the date the options are granted. The fair value of each option is estimated as of the date of grant using the Black-Scholes options-pricing model. In November 2010, the Company's Board of Directors approved the immediate vesting of all outstanding stock options under both the 1999 Plan and the 2009 Plan. Additionally, the Board authorized management to net-settle any outstanding stock options in cash. The option holder had a choice of receiving cash upon net settlement of options or to settle options for shares of the Company. Such modification of the stock options resulted in recognizing a liability equal to the portion of each award attributable to past service multiplied by the modified award's fair value, and was adjusted quarterly. The accelerated vesting and modification affected no other terms or conditions of the options, including the number of outstanding options or exercise price. During the fiscal year-ended June 30, 2012 and 2011, the Company recognized a total stock option expense of approximately $3,000, and $1.3 million, respectively. The aggregate intrinsic values of the options exercised/forfeited during fiscal years 2012 and 2011 were approximately $0.5 million and $8.9 million.

Restricted Stock

The Company did not grant any shares of restricted stock for the fiscal years ended June 30, 2013, 2012 or 2011.

13. Related Party Transactions

Juneau Exploration LLC.

In April 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 was paid an annual fee of $2.0 million.

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Effective January 1, 2013, the Advisory Agreement was terminated, and the Company and JEX entered into a First Right of Refusal Agreement (the "First Right Agreement"). Under the First Right Agreement, JEX grants a first right of refusal to Contango to purchase any exploration prospects generated and recommended by JEX. Prospects are presented along with terms and conditions for purchasing each prospect and Contango has the first right of refusal to purchase the prospect from JEX for a period of 10 days, subject to mutually acceptable terms. Pursuant to the First Right Agreement, JEX is paid an annual fee of $0.5 million which approximates the costs incurred by JEX for its continued support to the Company in the areas of operations, engineering, and land functions. JEX and its employees continue to be eligible to receive overriding royalty interests, carried interests and certain back-in rights. The First Right Agreement was terminated effective as of March 31, 2013.

Effective January 1, 2013, Contaro Company, a wholly-owned subsidiary of the Company, entered into an advisory agreement with JEX (the "Contaro Advisory Agreement"). Under the Contaro Advisory Agreement, JEX will provide advisory services to Contaro in connection with Contaro's investment in Exaro, and Mr. Juneau will serve on the Board of Managers of Exaro and perform such duties as described in the limited liability company operating agreement of Exaro. Pursuant to the Contaro Advisory Agreement, JEX will be paid a monthly fee of $10,000 and shall be entitled to receive a one percent (1%) fee of the cash profit earned by Contaro. Cash profit is defined as the amount of cash received by Contango as a result of its investment in Contaro, less the cash invested by the Company as a result of its investment in Contaro.

Olympic Energy Partners

In August 2012, the Company's founder, Chairman and Chief Executive Officer, Mr. Kenneth R. Peak, took a medical leave of absence and the board of directors of the Company appointed Mr. Juneau as President and Acting Chief Executive Officer of the Company. In December 2012, Mr. Joseph J. Romano was elected President and Chief Executive Officer of the Company. Mr. Peak passed away on April 19, 2013 and Mr. Romano was named Chairman of the Company. Mr. Romano is also the President and Chief Executive Officer of Olympic Energy Partners LLC ("Olympic").

JEX, affiliates of JEX, and Olympic have 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 ("WI"), net revenue interest ("NRI"), 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, excluding Mr. Juneau, except where otherwise noted. Olympic last participated with the Company in the drilling of wells in March 2010, and its ownership in Company-operated wells is limited to our Dutch and Mary Rose wells.

Republic Exploration LLC. In his capacity as sole manager of the general partner of JEX, Mr. Juneau also controls the activities of Republic Exploration LLC ("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.

As of June 30, 2013, Contango, Olympic, JEX, REX and JEX employees owned the following interests in the Company's offshore wells.

	Contango		Olympic		JEX		REX		JEX Employees
	WI	NRI	WI	NRI	WI	NRI	WI	NRI	ORRI
Dutch #1 - #5	47.05 %	38.12 %	3.02 %	2.42 %	1.61 %	1.29 %	— %	— %	2.02%
Mary Rose #1	53.21 %	40.44 %	3.61 %	2.70 %	2.01 %	1.51 %	— %	— %	2.79%
Mary Rose #2 - #3	53.21 %	38.67 %	3.61 %	2.58 %	2.01 %	1.44 %	— %	— %	2.79%
Mary Rose #4	34.58 %	25.49 %	2.34 %	1.70 %	1.31 %	0.95 %	— %	— %	1.82%
Mary Rose #5	37.80 %	27.88 %	2.56 %	1.87 %	1.43 %	1.04 %	— %	— %	1.54%

Ship Shoal 263	100.00 %	80.00 %	— %	— %	— %	— %	— %	— %	3.33%
Vermilion 170	83.20 %	64.83 %	— %	— %	4.30 %	3.35 %	12.50 %	9.74 %	3.33%

Below is a summary of transactions between the Company, Olympic, JEX, and REX during the fiscal years ended June 30, 2013, 2012 and 2011:

- In March 2010 the Company spud the Eloise South well. All owners paid for their proportionate share of drilling and completion costs based on their ownership percentage. The Company had a 23.8% working interest in this well, Olympic had a 3.33% working interest, and REX had a 9.6% working interest. Once production began, JEX employees received an ORRI of 1.33%.
- In June 2010 the Company spud its Rexer #1 well. Under the terms of the applicable participation agreement, the Company had a 100% working interest through payout of all costs. In May 2011, the Company sold Rexer #1 (See Note 5 - Discontinued Operations) prior to reaching payout. Once payout is reached with the new operator, JEX will have an option to back-in for a 10% working interest (7.25% net revenue interest). Other third-parties own the remaining working interests. JEX employees maintained a 2.5% ORRI in this well. The Company paid JEX a prospect fee of $250,000 for generating this prospect.
- In October 2010, the Company purchased JEX's 7.5% working interest in Ship Shoal 263 for $7.5 million, based on a reserve valuation as of the purchase date.

- Prior to its dissolution, Contango Offshore Exploration LLC 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 65.63% share of the obligation under the COE Note, while JEX assumed the remaining 34.37%, or approximately $2 million. This $2 million was paid to the Company in October 2010.

- In February 2011 the Company spud Vermilion 170 which was owned 100% by the Company. Under the terms of the applicable participation agreement, Contango had a 100% working interest through casing point. Once casing point was reached, JEX and REX each exercised their option to back-in for a 2.6% and 7.5% working interest, respectively. Once production began, JEX and REX each received their carried working interest of 1.7% and 5.0%, respectively, resulting in JEX having a final working interest of 4.3% and REX having a final working interest of 12.5%. The Company owns the remaining working interests in this well. The Company paid JEX a prospect fee of $250,000 for generating this prospect.

- In May 2011 the Company spud its Rexer-Tusa #2 well. Under the terms of the applicable participation agreement, the Company had a 25% working interest through payout of all costs. In October 2011, the Company completed selling Rexer-Tusa #2 (See Note 5 - Discontinued Operations) prior to reaching payout. Once payout is reached with the new operator, JEX will have an option to back-in for a 10% working interest (7.36% net revenue interest). Other third-parties own the remaining working interests. JEX employees maintained a 2.92% ORRI in this well.

- In July 2011, the Company recompleted its Eloise South well uphole in the Cib-Op sands as our Dutch #5 well. Under the terms of the applicable joint operating agreement, all Dutch #5 well owners were required to purchase the Eloise South well bore from the Eloise South owners (the "Dutch Well Cost Adjustment"). All Eloise South and Dutch #5 well owners paid and/or received their proportionate share of the Dutch Well Cost Adjustment based on their ownership percentage in each well. JEX had a 1.6% working interest in Dutch #5; Olympic had a 3.02% working interest in Dutch #5 and a 3.33% working interest in Eloise South; REX had a 9.6% working interest in Eloise South; and Contango had a 47.05% working interest in Dutch #5 and a 23.8% working interest in Eloise South.

- In December 2011, the Company purchased an additional working interest in Mary Rose #5 (see below) from an existing partner. The Company then sold to Olympic and JEX its proportionate share of the existing partner's interest, based on Olympic and JEX's ownership percentage in the well.

- In January 2012, the Company recompleted its Eloise North well uphole in the Cib-Op sands as our Mary Rose #5 well. Under the terms of the applicable joint operating agreement, all Mary Rose #5 well owners were required to purchase the Eloise North well bore from the Eloise North owners. (the "Mary Rose Well Cost Adjustment"). All

Eloise North and Mary Rose #5 well owners paid and/or received their proportionate share of the Mary Rose Well Cost Adjustment based on their ownership percentage in each well. JEX had a 1.4% working interest in Mary Rose #5 and a 0.1% working interest in Eloise North; Olympic had a 2.56% working interest in Mary Rose #5 and a 4.79% working interest in Eloise North; REX had a 13.2% working interest in Eloise North; and the Company had a 37.8% working interest in Mary Rose #5 and a 35.8% working interest in Eloise North.

- In March 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. Under the terms of the applicable participation agreement, if the lease becomes a prospect, Contango will have a 100% working interest through casing point. Once casing point is reached, JEX may exercise its option to back-in for a 5% working interest. Once production begins (if successful), JEX will receive a carried working interest of 3.33%, resulting in JEX having a final working interest of 8.33% (6.49% net revenue interest) Contango will have a 75% working interest (58.44% net revenue interest),with third parties owning the remaining working interests. JEX employees will have a 2.33% working interest in this well. If the lease is developed into a prospect, the Company will pay JEX a prospect fee of $250,000 for generating this prospect.

- In July 2012 the Company spud the Ship Shoal 134 prospect which was owned 100% by the Company. The Company paid 100% of the costs to drill, plug and abandon this well. The Company paid JEX a prospect fee of $250,000 for generating this prospect.

- In July 2012 the Company spud the South Timbalier 75 prospect which was farmed-in 100% by the Company and REX. Under the terms of the applicable participation agreement, the Company paid 100% of the costs to drill, plug and abandon this well. The Company paid JEX a prospect fee of $250,000 for generating this prospect.

- For the five REX-generated lease blocks that the Company purchased at the June 20, 2012 lease sale, the Company will have a 100% working interest through first production. At first production (if successful), REX will receive a carried working interest of 10%. Once payout of post casing point costs has been reached, REX will have an option to back-in for up to 12.5% working interest, resulting in REX having a final working interest of up to 22.5% (17.5% net revenue interest) and the Company owning the remaining working interests. JEX employees will receive an ORRI of 3.33% in these prospects.

- For the one JEX-generated lease block that the Company purchased at the June 20, 2012 lease sale, the Company will carry JEX for 10% through first production and JEX employees will receive an ORRI of 3.33%.

- For the three REX-generated lease blocks that the Company purchased at the March 20, 2013 lease sale, the Company will have a 100% working interest through first production. At first production (if successful), REX will receive a carried working interest of 10%. Once payout of post casing point costs has been reached, REX will have an option to back-in for up to 12.5% working interest, resulting in REX having a final working interest of up to 22.5% (17.5% net revenue interest) and the Company owning the remaining working interests. JEX employees will receive an ORRI of 3.33% in these prospects.

- In June 2013, the Company purchased South Timbalier 17 from an independent oil and gas company. Under the terms of the applicable participation agreement, the Company will have a 75% working interest in this well, with several other owners owning the remainder, until payout of all costs is reached. Once payout of all costs has been reached, REX will have an option to back-in for up to a 9.4% working interest, (6.7% net revenue interest), resulting in the Company owning a 56.3% working interests (39.9% net revenue interest). The Company paid JEX a prospect fee of $250,000 for evaluating this prospect. There are no JEX employee ORRIs on this prospect.

- In the Tuscaloosa Marine Shale ("TMS"), a shale play in central Louisiana and Mississippi, the Company has a 100% working interest through first production. At first production of the existing acreage (if successful), JEX will receive a carried working interest of 10% and JEX employees will receive an ORRI of 2%, of which Mr. Juneau receives 0.75%, due to fees to third parties paid by JEX in order to get into the prospect, that were not billed to Contango. An additional 2% was granted to the geologist who is responsible for the generation of the TMS prospect. The geologist has subsequently been employed by JEX.

Below is a summary of payments received from (paid to) Olympic, JEX, and REX in the ordinary course of business in our capacity as operator of the wells and platforms for the periods indicated. The Company made and received similar types

of payments with other well owners (in thousands):

	2013			2012			2011		
	Olympic	JEX	REX	Olympic	JEX	REX	Olympic	JEX	REX
Revenue payments as well owners	$(6,455)	$(4,380)	$(2,449)	$(8,453)	$(5,719)	$(3,166)	$(10,406)	$(6,089)	$(1,908)
Joint interest billing receipts	1,122	1,170	1,430	1,223	928	2,422	1,480	1,437	2,068
Dutch well cost adjustment	—	—	—	—	—	—	(389)	161	(957)
Mary Rose well cost adjustment	—	—	—	(201)	118	(1,185)	—	—	—

Below is a summary of payments received from (paid to) Olympic, JEX and REX as a result of specific transactions between the Company, Olympic, JEX and REX. While these payments are in the ordinary course of business, the Company did not have similar transactions with other well owners (in thousands):

	2013			2012			2011		
	Olympic	JEX	REX	Olympic	JEX	REX	Olympic	JEX	REX
Sale of interest in Mary Rose #5	$—	$—	$—	$—	$8	$—	$—	$—	$—
Reimbursement of certain costs	—	(546)	(5)	—	(325)	(17)	—	(206)	(302)
Prospect fees	—	(750)	—	—	(250)	—	—	—	—
Advisory Agreement	—	(1,000)	—	—	(500)	—	—	—	—
First Right Agreement	—	(125)	—	—	—	—	—	—	—
Contaro Advisory Agreement	—	(50)	—	—	(30)	—	—	—	—
Purchase of Ship Shoal 263	—	—	—	—	—	—	—	(7,512)	—
REX distribution to members	—	—	646	—	—	823	—	—	—
Repayment of COE Note	—	—	—	—	—	—	—	2,028	—
Exploration costs in Alaska	—	—	—	—	—	—	—	(906)	—

As of June 30, 2013 and 2012, the Company's consolidated balance sheets reflected the following balances (in thousands):

	2013			2012		
	Olympic	JEX	REX	Olympic	JEX	REX
Accounts receivable:						
Trade receivable	16	21	—	26	20	18
Joint interest billing	178	358	922	193	158	92
Accounts payable:						
Royalties and revenue payable	(609)	(425)	(221)	(611)	(813)	(682)

Contango ORE, Inc. Contango Mining Company (“Contango Mining”), a wholly owned subsidiary of the Company, was formed in October 2009 for the purpose of engaging in exploration in the state of Alaska for (i) gold ore and associated minerals and (ii) rare earth elements. Contango Mining initially acquired a 50% interest in these properties in Alaska from JEX in exchange for $1 million and a 1% ORRI in the properties under a Joint Exploration Agreement (the “Joint Exploration Agreement”). We believe JEX expended approximately $1 million on exploratory activities and related work on the properties prior to selling the initial 50% interest to Contango Mining. Contango Mining also agreed to fund the next $2 million of exploration costs. During the fiscal year ended June 30, 2011 and 2010, Contango Mining paid JEX approximately $0.9 million and $0.5 million, respectively, for exploration costs incurred by JEX in the state of Alaska.

In September 2010, Contango Mining acquired the remaining 50% interest in the properties by increasing the ORRI in the properties granted to JEX to 3% pursuant to an Amended and Restated Conveyance of Overriding Royalty Interest (the “Amended ORRI Agreement”). Contango Mining assumed control of the exploration activities and JEX and Contango Mining terminated the Joint Exploration Agreement.

Contango ORE, Inc. ("CORE") was formed on September 1, 2010 as a wholly-owned subsidiary of the Company and in November 2010, Contango Mining assigned the properties and certain other assets and liabilities to Contango. Contango contributed the properties and $3.5 million of cash to CORE, pursuant to the terms of a Contribution Agreement (the "Contribution Agreement"), in exchange for approximately 1.6 million shares of CORE's common stock. The transactions took place between companies under common control. Contango distributed all of CORE's common stock to Contango's stockholders of record as of October 15, 2010, promptly after the effective date of CORE's Registration Statement Form 10 on the basis of one share of common stock for each ten (10) shares of Contango's common stock then outstanding.

In November 2011, the Company executed a $1.0 million Revolving Line of Credit Promissory Note to lend money to CORE (the "CORE Note"). The Company and CORE share executive officers. The CORE Note contains covenants limiting CORE's ability to enter into additional indebtedness and prohibiting liens on any of its assets or properties. Borrowings under the CORE Note bear interest at 10% per annum. Principal and interest are due from CORE to the Company on December 31, 2012, and may be prepaid at any time with no prepayment penalty.

On March 30, 2012 the Company received repayment of the $500,000 it had advanced under the CORE Note, plus accrued interest of approximately $15,000. As of June 30, 2012, there are no amounts outstanding under the CORE Note. CORE had the option to re-borrow any portion of the $1.0 million through December 31, 2012.

Equity Compensation. In February 2012, the Company net-settled 45,000 stock options from two employees for a total of approximately $465,000. During the fiscal year ended June 30, 2011, the Company purchased 172,544 shares of its common stock for a total of approximately $9.8 million. Of this amount, 149,573 shares were purchased from four employees and one member of its board of directors for a total of approximately $8.7 million. During the fiscal year ended June 30, 2010, the Company purchased 115,454 shares of its common stock from three officers of the Company and two members of its board of directors for approximately $6.4 million. All the purchases were approved by the Company's board of directors and were completed at the closing price of the Company's common stock on the date of purchase.

14. Share Repurchase Programs

$100 Million Share Repurchase Program

In September 2008, the Company's board of directors approved a $100 million share repurchase program which concluded in October 2011. Under this share repurchase program, the Company purchased a total of 2,157,278 shares of common stock at an average price of $46.35 per share. All shares were purchased in the open market or through privately negotiated transactions. The purchases were made subject to market conditions and certain volume, pricing and timing restrictions to minimize the impact of the purchases upon the market, and when we believed the Company's stock price to be undervalued. Repurchased shares of common stock became authorized but unissued shares, and may be issued in the future for general corporate and other purposes.

$50 Million Share Repurchase Program

In September 2011, the Company's board of directors approved a $50 million share repurchase program, effective upon completion of purchases under the Company's $100 million share repurchase program. The purchases made under the $50 million share repurchase program are subject to the same terms and conditions as purchases made under the $100 million share repurchase program. During the fiscal year ended June 30, 2013, the Company purchased 97,496 shares at an average price of $50.82 per share, for a total of approximately $5.0 million under the $50 million share repurchase program.

As of June 30, 2013, under under both share repurchase programs combined, the Company has purchased approximately 2.4 million shares of its common stock at an average cost per share of $46.84 and 45,000 stock options from two employees for a total of $465,000, for a total of approximately $110.8 million, bringing its total share count as of June 30, 2013 to 15,194,952 shares of common stock and no options outstanding.

15. Subsequent Events

In August 2013, Alta signed a contract to sell its interest in the Kaybob Duvernay. Proceeds from the sale are expected to be approximately $29 million, net to Contango. The sale is expected to close by October after satisfaction of a number of closing conditions. Contango has a 2% interest in Alta and a 5% interest in the Kaybob Duvernay project.

On July 30, 2013, we spud our South Timbalier 17 prospect with the Hercules 202 rig, and on August 22, 2013 announced an exploration discovery. Estimated costs net to Contango to drill, complete and bring this well to full production status are $12.5 million.

16. Merger with Crimson Exploration Inc.

On April 29, 2013, the Company and Crimson entered into a Merger Agreement, pursuant to which Crimson will become a wholly owned subsidiary of the Company.

Subject to the terms and conditions of the Merger Agreement, each share of Crimson common stock will be converted into 0.08288 shares of common stock of the Company. The Merger is intended to qualify as a tax-free reorganization for U.S. federal income tax purposes, so that none of the Company, Crimson, Merger Sub or Crimson's stockholders will recognize any gain or loss in the Merger, except that Crimson's stockholders may recognize gain or loss with respect to cash received in lieu of fractional shares of Company common stock.

The closing of the Merger is subject to the satisfaction or waiver of certain customary conditions, including, among others, (i) the adoption of the Merger Agreement by Crimson's stockholders; (ii) the approval by the Company's stockholders of the issuance of Company common stock in the Merger to Crimson's stockholders; (iii) the registration statement on Form S-4 used to register the Company common stock to be issued in the Merger being declared effective by the Securities and Exchange Commission (the “SEC”); (iv) the approval for listing on the New York Stock Exchange of the Company common stock to be issued in the Merger; (v) subject to specified materiality standards, the accuracy of the representations and warranties of, and the performance of all covenants by, the parties; (vi) the absence of a material adverse effect with respect to each of Crimson and the Company; and (vii) the delivery of tax opinions that the Merger will be treated as a “reorganization” within the meaning of Section 368(a) of the Internal Revenue Code.

The Company has agreed that, upon the Closing, it will cause the Board of Directors to consist of eight directors, three of whom will be appointed by the board of directors of Crimson and five of whom will be appointed by Contango's Board of Directors. Additionally, Joseph J. Romano (the current Chairman, President and Chief Executive Officer of the Company) will serve as Chairman of the Board, Allan D. Keel (the current President and Chief Executive Officer of Crimson) will serve as President and Chief Executive Officer of the Company, and E. Joseph Grady (the current Senior Vice President and Chief Financial Officer of Crimson) will serve as Senior Vice President and Chief Financial Officer of the Company. Messrs. Keel, Grady and certain other employees of Crimson entered into employment agreements with the Company that become effective upon the consummation of the Merger. The combined company will have its headquarters and principal corporate office in Houston, Texas.

In connection with the execution of the Merger Agreement, the Company concurrently entered into a Stockholder Support and Irrevocable Proxy Agreement with each of (a) OCM Crimson Holdings, LLC and OCM GW Holdings, LLC (collectively, “Oaktree”) and (b) Allan D. Keel, E. Joseph Grady, A. Carl Isaac, Jay S. Mengle, Thomas H. Atkins and John A. Thomas, each of whom is an executive officer of Crimson, (collectively, the “Crimson Support Agreements”). The shares of Crimson common stock outstanding that are beneficially owned by Oaktree and such executive officers of Crimson and are subject to the Crimson Support Agreements represent, in the aggregate, approximately 38.8% of Crimson's outstanding common stock as of April 29, 2013. Pursuant to the Crimson Support Agreements, Oaktree and each signatory executive officer of Crimson agrees to vote the shares it beneficially owns (i) in favor of the Merger and the Merger Agreement and (ii) against (a) any other acquisition proposal, (b) any liquidation, dissolution, recapitalization, extraordinary dividend or other significant corporate reorganization of Crimson, and (c) any other action, proposal or agreement that would reasonably be expected to interfere with or delay the consummation of the Merger. The Crimson Support Agreements terminate at the earliest of the effective time of the Merger, the termination of the Merger Agreement in accordance with its terms or any reduction of the Merger Consideration.

Additionally, in connection with the execution of the Merger Agreement, Crimson concurrently entered into a Stockholder Support Agreement (collectively, the “Company Support Agreements”) with the Estate of Kenneth R. Peak, Joseph J. Romano, Brad Juneau, Sergio Castro and Yaroslava Makalskaya who, in the aggregate, beneficially own approximately 10.6% of the Company's outstanding common stock as of April 29, 2013. Pursuant to the Company Support Agreements, the Estate of Kenneth R. Peak and each signatory executive officer and director of the Company agrees to vote their shares of the Company's common stock in favor of the Merger and against any other acquisition proposal.

The foregoing descriptions of the Merger Agreement and related agreements are qualified in their entirety by reference to the full text of such agreements.

As of June 30, 2013, we had incurred approximately $3.0 million in expenditures associated with the Merger. We will continued to incur additional Merger-related costs, including a success fee of $2.7 million. The Merger is expected to close in October 2013.

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

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

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

	Year Ended June 30,		
	2013	2012	2011
Property acquisition costs:		(thousands)	
Unproved	$16,130	$5,404	$2,802
Proved	102	381	10,135
Exploration costs	47,584	1,154	14,016
Development costs	11,758	10,350	39,211
Total costs incurred	$75,574	$17,289	$66,164

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

	Year Ended June 30,		
	2013	2012	2011
		(thousands)	
Property acquisition costs	$—	$—	$—
Exploration costs	—	—	—
Development costs	46,972	785	—
Company's 37% share of costs incurred	$46,972	$785	$—

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

Proved natural gas and oil reserve quantities at June 30, 2012, 2011, 2010 and 2009, and the related discounted future net cash flows before income taxes are based on estimates prepared by William M. Cobb & Associates, Inc. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

The below table summarizes the Company’s net ownership interests in estimated quantities of proved natural gas, oil and natural gas liquids (“NGLs”) reserves and changes in net proved reserves as of June 30, 2013, 2012, 2011, and 2010, all of which are located in the continental United States. There were no material reserves associated with our equity investments.

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

	Oil and Condensate (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)
Proved Developed and Undeveloped Reserves as of:			
June 30, 2010	4,598	6,738	246,011
Sale of minerals in place	(126)	(648)	(16,804)
Extensions and discoveries	565	191	31,585
Purchases of minerals in place	53	9	929
Revisions of previous estimates	73	(302)	2,584
Production	(685)	(702)	(26,160)
June 30, 2011	4,478	5,286	238,145
Sale of minerals in place	—	—	—
Extensions and discoveries	—	—	—
Purchases of minerals in place	—	—	—
Revisions of previous estimates	(551)	1,262	(13,149)
Production	(615)	(662)	(23,617)
June 30, 2012	3,312	5,886	201,379
Sale of minerals in place	—	—	—
Extensions and discoveries	81	—	—
Purchases of minerals in place	—	—	—
Revisions of previous estimates	(703)	(1,141)	(33,714)
Production	(362)	(601)	(18,658)
June 30, 2013	2,328	4,144	149,007
Proved Developed Reserves as of:			
June 30, 2010	4,328	6,167	231,260
June 30, 2011	3,738	5,037	205,085
June 30, 2012	3,353	5,664	196,268
June 30, 2013	2,297	4,078	146,518
Proved Undeveloped Reserves as of:			
June 30, 2010	270	571	14,751
June 30, 2011	740	249	33,060
June 30, 2012	(41)	222	5,111
June 30, 2013	31	66	2,489
Company's Share of Proved Developed Reserves attributable to our 37% investment in Exaro:			
June 30, 2012	20	—	1,683
June 30, 2013	309	—	28,320

The change in reserves during the fiscal year ended 2013 was attributable to production of 24.4 Bcfe and reserve revisions of 44.8 Bcfe. The Company's reservoir engineer decreased the Company's estimated reserves at our Dutch, Mary Rose, Vermilion 170, and Ship Shoal 263 wells by approximately 44.8 Bcfe, due to new information obtained. The most significant change to our reserves during the fiscal year ended June 30, 2012 was current year production. During the fiscal year ended June 30, 2011, the most significant changes were associated with our discovery at Vermilion 170 and the sale of our Joint Venture Asset reserves (see Note 5 – Discontinued Operations).

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

Standardized Measure. The standardized measure of discounted future net cash flows relating to the Company's ownership interests in proved natural gas and oil reserves as of June 30, 2013, 2012 and 2011 are shown below:

	As of June 30, 2013	2012	2011
	(thousands)		
Future cash inflows	$956,886	$1,378,910	$1,801,236
Future production costs	(170,159)	(301,137)	(313,688)
Future development costs	(22,507)	(31,214)	(52,053)
Future income tax expenses	(268,290)	(312,211)	(406,306)
Future net cash flows	495,930	734,348	1,029,189
10% annual discount for estimated timing of cash flows	(138,413)	(220,416)	(312,054)
Standardized measure of discounted future net cash flows	$357,517	$513,932	$717,135
Contango's share of standardized measure of discounted future net cash flows attributable to our 37% investment in Exaro	$42,464	$2,733	$—

Future cash inflows represent expected revenues from production and are computed by applying certain prices of natural gas and oil to estimated quantities of proved natural gas and oil reserves. Prices are based on the first-day-of-the-month prices for the previous 12 months. For the fiscal year ended June 30, 2013, future cash inflows were based on prices of $3.44 per MMbtu of natural gas, $91.57 per barrel of oil, and $39.50 per barrel of NGLs. For the fiscal year ended June 30, 2012, future cash inflows were based on $3.13 per MMBtu of natural gas, $96.07 per barrel of oil, and $59.39 per barrel of natural gas liquids. For the fiscal year ended June 30, 2011, future cash inflows were based on of $4.25 per MMBtu of natural gas, $90.27 per barrel of oil, and $55.78 per barrel of natural gas liquids, in each case before adjustments for basis, transportation costs and BTU content.

Realized Prices. The average realized prices for the reserves presented in this report are $3.58 per MCF of gas, $111.25 per barrel of oil, and $39.50 per barrel of NGL.

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

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

The Company's share of the standardized measure of discounted future net cash flows attributable to our investment in Exaro does not include the effect of income taxes because Exaro is treated a partnership for tax purposes. Exaro allocates any income or expense for tax purposes to its partners.

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

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

	Year Ended June 30,		
	2013	2012	2011
Changes in standardized measure due to current year operation:	(thousands)		
Sales of natural gas and oil produced during the period, net of production expenses	$(112,469)	$(160,111)	$(188,810)
Extensions and discoveries	2,956	—	160,712
Net change in prices and production costs	8,186	(144,533)	5,401
Changes in estimated future development costs	9,399	17,322	41,989
Revisions in quantity estimates	(131,245)	(25,486)	4,078
Purchase of reserves	—	—	6,556
Sale of reserves	—	—	(20,031)
Accretion of discount	73,022	98,104	97,044
Changes in income taxes	23,470	47,616	(5,558)
Change in the timing of production rates and other	(29,734)	(36,115)	(96,340)
Net change	(156,415)	(203,203)	5,041
Beginning of year	513,932	717,135	712,094
End of year	$357,517	$513,932	$717,135

For the fiscal year ended June 30, 2013, the standardized measure decreased by approximately $156.4 million. Of this amount, approximately $112.5 million was related to current year production and approximately $131.2 million was related to reserves revisions, offset by accretion. For the fiscal year ended June 30, 2012, the standardized measure decreased by approximately $203.2 million, principally due to a decrease in natural gas and oil prices and production during the year.

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

Quarterly Results of Operations. The following table sets forth the results of operations by quarter for the years ended June 30, 2013 and 2012:

	Quarter Ended			
	September 30, 2012	December 31, 2012	March 31, 2013	June 30, 2013
	(thousands, except per share amounts)			
Fiscal Year 2013:				
Revenues from continuing operations	$29,765	$34,940	$31,787	$30,709
Net income (loss) from continuing operations (1)	$(27,549)	$2,604	$3,869	$11,356
Net income (loss) attributable to common stock	$(27,549)	$2,604	$3,869	$11,356
Net income (loss) per share (2):				
Basic:	$(1.80)	$0.17	$0.25	$0.75
Diluted:.	$(1.80)	$0.17	$0.25	$0.75
Fiscal Year 2012:				
Revenues from continuing operations	$44,203	$53,907	$41,339	$39,823
Income from continuing operations (1)	15,586	19,589	14,699	9,339
Net loss from discontinued operations, net of taxes	(682)	(114)	(26)	(2)
Net income attributable to common stock	14,904	19,475	14,673	9,337
Net income per share (2):				
Basic:	$0.95	$1.27	$0.96	$0.61
Diluted:.	$0.95	$1.27	$0.96	$0.61

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

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