Resolute Energy Corp
Form 10-K
March 07, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2012

OR

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

For the transition period from _________ to _________

Commission File No. 001-34464

RESOLUTE ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

Delaware	**27-0659371**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
1675 Broadway, Suite 1950 Denver, CO	**80202**
(Address of principal executive offices)	**(Zip Code)**

(303) 534-4600

(Registrant s telephone number, including area code)

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, par value $0.0001 per share	**New York Stock Exchange**
Warrants, each exercisable for one share of Common Stock	**New York Stock Exchange**

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

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 of the Exchange 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 delinquent filers pursuant to item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant s knowledge, indefinite 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.

Large accelerated filer	¨	Accelerated filer	x
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	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

The aggregate market value of registrant s common stock held by non-affiliates on June 30, 2012, computed by reference to the price at which the common stock was last sold as posted on the New York Stock Exchange, was $355.7 million.

As of February 28, 2013, 61,855,709 shares of the Registrant s $0.0001 par value Common Stock were outstanding.

The following documents are incorporated by reference herein: Portions of the definitive Proxy Statement of Resolute Energy Corporation to be filed pursuant to Regulation 14A of the general rules and regulations under the Securities Exchange Act of 1934, as amended, for the 2013 annual meeting of stockholders (Proxy Statement) are incorporated by reference into Part III of this Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements as that term is defined in the Private Securities Litigation Reform Act of 1995. The use of any statements containing the words anticipate, intend, believe, estimate, project, expect, plan, should or similar e are intended to identify such statements. Forward-looking statements included in this report relate to, among other things, expected future production, expenses and cash flows in 2013 and beyond, the nature, timing and results of capital expenditure projects, our ability to improve efficiency and control costs, expiration of leases that are not held by production, amounts of future capital expenditures, drilling plans and exploration and development activities, our plans with respect to the identification, consummation and integration of future acquisitions, our future debt levels and liquidity and future derivative activities and future compliance with covenants under our revolving credit facility and senior notes. Although we believe that these statements are based upon reasonable current assumptions, no assurance can be given that the future results covered by the forward-looking statements will be achieved. Forward-looking statements can be subject to risks, uncertainties and other factors that could cause actual results to differ materially from future results expressed or implied by the forward-looking statements. The forward-looking statements in this report are primarily located under the heading Risk Factors. All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we undertake no obligation to update any forward-looking statement. Factors that could cause actual results to differ materially from our expectations include, among others, those factors referenced in the Risk Factors section of this report and such things as:

- volatility of oil and gas prices, including reductions in prices that would adversely affect our revenue, income, cash flow from operations, liquidity and reserves, discovery, estimation and development of, and our ability to replace oil and gas reserves;
- our future cash flow, liquidity and financial position;
- the success of our business and financial strategy, derivative strategies and plans;
- the amount, nature and timing of our capital expenditures, including future development costs;
- our relationship with the Navajo Nation, the local community in the area where we operate, and Navajo Nation Oil and Gas Company, as well certain purchase rights held by Navajo Nation Oil and Gas Company;
- a lack of available capital and financing, including the capital needed to pursue our production and other plans for the Permian Properties (as defined below), on acceptable terms, including as a result of a reduction in the borrowing base under our credit facility;
- the effectiveness and results of our CO_2 flood program;
- the impact of U.S. and global economic recession;
- anticipated CO_2 supply, which is currently sourced exclusively from Kinder Morgan CO_2 Company, L.P.;
- the success of the development plan for and production from our oil and gas properties, particularly our Aneth Field Properties;

the timing and amount of future production of oil and gas;

the completion, timing and success of exploratory drilling;

availability of, or delays related to, drilling, completion and production, personnel, supplies and equipment;

the effect of third party activities on our oil and gas operations, including our dependence on gas gathering and processing systems;

inaccuracy in reserve estimates and expected production rates;

our operating costs and other expenses;

our success in marketing oil and gas;

competition in the oil and gas industry;

the concentration of our producing properties in a limited number of geographic areas;

operational problems, or uninsured or underinsured losses affecting our operations or financial results;

the impact and costs related to compliance with, or changes in, laws or regulations governing our oil and gas operations, including the potential for increased regulation of underground injection or fracing operations;

the availability of water and our ability to adequately treat and dispose of water after drilling and completing wells;

potential changes to regulations affecting derivatives instruments;

the success of our derivatives program;

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- the impact of weather and the occurrence of disasters, such as fires, explosions, floods and other events and natural disasters;
- environmental liabilities under existing or future laws and regulations;
- developments in oil and gas producing countries;
- loss of senior management or key technical personnel;
- timing of issuance of permits and rights of way;
- timing of installation of gathering infrastructure in areas of new exploration and development;
- potential breakdown of equipment and machinery relating to the Aneth compression facility;
- our ability to achieve the growth and benefits we expect from the Permian Acquisitions (as defined below);
- risks associated with unanticipated liabilities assumed, or title, environmental or other problems resulting from, the Permian Acquisitions;
- acquisitions and other business opportunities (or the lack thereof) that may be presented to and pursued by us, and the risk that any opportunity currently being pursued will fail to consummate or encounter material complications;
- risks related to our level of indebtedness;
- our ability to fulfill our obligations under the senior notes;
- a lack of available capital and financing on acceptable terms, including as a result of a reduction in the borrowing base under our credit facility;
- constraints imposed on our business and operations by our credit agreement and our senior notes to generate sufficient cash flow to repay our debt obligations;
- losses possible from pending or future litigation;
- risk factors discussed or referenced in this report; and

other factors, many of which are beyond our control.

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PART I

ITEMS 1. and 2. BUSINESS AND PROPERTIES

As used in this Annual Report on Form 10-K, unless the context otherwise requires or indicates, references to Resolute, the Company, we, our, ours, and us refer to Predecessor Resolute (as defined below in Selected Financial Data) for all periods prior to September 25, 2009 and Resolute Energy Corporation and its subsidiaries for all periods thereafter.

Business Overview

We are a publicly traded, independent oil and gas company engaged in the exploitation, development, exploration for and acquisition of oil and gas properties. Our asset base is comprised of properties in Aneth Field located in the Paradox Basin in southeast Utah (the Aneth Field Properties or Aneth Field), the Permian Basin in Texas and southeast New Mexico (the Permian Properties), the Williston Basin in North Dakota (the Bakken Properties) and the Big Horn and Powder River Basins in Wyoming (the Wyoming Properties). Our primary operational focus is on increasing reserves and production from these properties while improving efficiency and optimizing operating costs. We plan to expand our reserve base through an organic growth strategy focused on the expansion of tertiary oil recovery in Aneth Field, the exploitation and development of oil-prone acreage, particularly in our Permian and Bakken Properties, and through carefully targeted exploration activities in our Wyoming Properties. We also expect to engage in other opportunistic acquisitions.

On December 21, 2012, we purchased properties containing proved reserves of approximately 4.1 million equivalent barrels of oil (MMBoe) in Denton Field in the Northwest Shelf in Lea County, New Mexico and in the Spraberry trend in the Midland Basin portion of the Permian Basin in Howard County, Texas, for a purchase price of approximately $115 million. Additionally, on December 28, 2012, we purchased properties containing proved reserves of approximately 5.1 MMBoe in the Wolfberry Play in the Delaware Basin portion of the Permian Basin in Midland and Ector counties, Texas, for a purchase price of approximately $127 million. We refer to the properties acquired under these acquisitions as the New Permian Properties. Concurrently we acquired, for additional consideration of $5.7 million, the option to buy the balance of the working interest in and operatorship of the properties for additional consideration of approximately $261 million, under substantially the same terms as the initial transaction, at any time between the closing date and March 18, 2013 (the Option Properties). The $5.7 million option fee will be credited toward the purchase price if exercised. The closing of the acquisitions, which we refer to as the Permian Acquisitions, were financed from the net proceeds of a $150 million senior notes offering in December 2012 and borrowings under our revolving credit facility. On March 3, 2013, we indicated our intent to purchase the Option Properties and expect to close the transaction on or about March 22, 2013.

During 2012, oil sales comprised approximately 93% of revenue, and our December 31, 2012, estimated net proved reserves were approximately 78.8 MMBoe, of which approximately 59% and 43% were proved developed reserves and proved developed producing reserves, respectively. Approximately 79% of our estimated net proved reserves were oil and approximately 90% were oil and natural gas liquids (NGL). The December 31, 2012, pre-tax present value discounted at 10% (PV-10) of our net proved reserves was $1,127 million and the standardized measure of our estimated net proved reserves was $872 million. For additional information about the calculation of our PV-10 and standardized measure, please read *Business and Properties Estimated Net Proved Reserves*.

Business Strategies

Our business strategies aim to create value for our stakeholders by growing reserves, production volumes and cash flow utilizing industry standard enhanced oil recovery techniques as well as advanced development, drilling and completion technologies to systematically explore for, develop and produce oil and gas reserves. Key elements of our business strategies include:

Expand Production Within our Aneth Field CO_2 Flood. We intend to increase production in Aneth Field through activities targeted at converting non-producing reserves into production, such as the McElmo Creek Unit IIC subzone of the Desert Creek formation (the DC IIC) CO_2 expansion, installing equipment to separate CO_2 from saleable hydrocarbon gas, and bringing new reserves into the proved category by expanding the CO_2 flood into the Ratherford Unit. Proved developed non-producing and proved undeveloped reserves at year end constitute 17% and 45%, respectively, of the proved reserves in Aneth Field. These reserves primarily relate to the CO_2 flood that we commenced in 2006, which followed a successful CO_2 flood implemented in a portion of the field by a prior operator in 1985. Using a phased approach, we have been expanding this CO_2 flood within the field with demonstrable success.

Existing production from the Aneth Field Properties, which is approximately 97% oil, generates strong cash flow. We anticipate this will fund all of the capital requirements of expanding the CO_2 flood over the next five years and will provide free cash flow that we anticipate redeploying in the development of our Bakken and Permian Properties, in our exploration-focused activities and, potentially, in acquisition opportunities.

Pursue Acquisitions of Properties with Development Potential in Core Areas. One component of our strategy has been to grow our reserves and production by acquiring domestic onshore properties. The Permian Acquisitions represent significant progress in furthering our growth in this manner. Prior to the Permian Acquisitions, our predecessor company acquired the majority of our Aneth Field Properties in 2004 and 2006 and our Hilight Field in 2008. Our Bakken Properties were acquired in 2010 and 2011 and the original component of our Permian Properties was acquired in 2011. We continue to actively evaluate opportunities to acquire properties that are prospective for production of oil and NGL, particularly in the Permian Basin and Rocky Mountain regions. Our knowledge of various producing basins and our experienced management team with long-standing industry relationships position us to continue to identify, consummate and integrate strategic acquisitions. Future acquisitions may require us to incur additional indebtedness.

Focus on Exploitation and Development of Oil and Liquids-Prone Formations on Existing Properties. We have assembled a portfolio of low-risk properties with acreage in three of the most active oil-focused resource plays in the United States. We have active drilling programs in the Bakken trend in the Williston Basin of North Dakota and in the Wolfbone and Wolfberry plays in the Permian Basin. Both of these areas are characterized by relatively low risk drilling, with production heavily weighted toward oil and NGL. We are focused on maximizing returns from these projects by optimizing completion techniques to enhance well performance and ultimate recoveries and accelerating development activity to increase near-term production and reserves.

Focus on Efficiency of Operations on Our Properties. We seek to maximize economic returns on our properties through operating efficiencies and cost control improvements. Our management team has significant experience in managing intensive oil and gas operations. As the operator of our Aneth Field Properties, Wyoming Properties, the majority of the Permian Properties and certain Bakken Properties, we have the ability to directly manage our costs, control the timing of our exploitation, drilling and producing activities and effectively implement programs to increase production and improve operational efficiency.

Establish Future Core Areas Through Focused Exploration Efforts. We control acreage in the Powder River and Big Horn basins of Wyoming which represent two emerging exploration plays. We own leases covering approximately 45,400 net acres in the Powder River Basin, all of which is held by production from the Muddy formation. We are conducting geologic studies of the area, integrating well logs and mapping the target formations. In the Big Horn Basin, we own leases covering approximately 76,000 net acres in which our primary target is the Frontier and Phosphoria formations and the Mowry oil shale. We may seek to attract industry and financial participants to these activities in order to leverage our capital and to mitigate risk.

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our business strategies, including:

A High Quality Base of Long-Lived Oil Producing Properties. As of December 31, 2012, we had estimated net proved reserves of approximately 78.8 MMBoe, of which approximately 79% were oil and approximately 90% were oil and NGL. Based on our 2012 year-end reserve report, our total proved reserve to production ratio was 23 years. The shallow decline rate and long lives of our core producing properties result in a slower reserve depletion rate and reduced reinvestment requirements relative to other producing areas in the United States.

Legacy Producing Assets Generating Strong Free Cash Flow. Our legacy producing asset base is anchored by three core properties, Aneth Field in Utah, the Permian Properties in Texas and New Mexico and Hilight Field in Wyoming. These properties have characteristics that we believe will provide a stable production platform and generate positive free cash flow to fund our development and growth activities.

Portfolio of Significant Organic Development and Drilling Opportunities. In addition to the expansion of our CO_2 flood in Aneth Field, we have attractive, low-risk positions in three of the most active oil resource plays in the United States as well as exposure to emerging oil-prone exploration plays in the Rocky Mountains. We believe that this portfolio provides an attractive drilling inventory in excess of 10 years.

Operating Control Over Our Properties. We have the ability to control the timing, scope and costs of most development projects undertaken on our various properties. We operate our Aneth Field, Wyoming Properties and a portion of our Permian and Bakken Properties, which constitute approximately 87% of our proved reserves. Further, operatorship of our Aneth Field and Wyoming Properties is secured for the foreseeable future as the acreage is held by production. We operate approximately 29% and 80% of our acreage in the Bakken and Permian Properties, respectively.

Strong Balance Sheet. We employ a disciplined approach to liquidity and management of leverage and have a capital structure that provides us with the ability to execute our business plan. At December 31, 2012, borrowings outstanding were $162 million under our revolving credit facility and $400 million under our 8.5% senior notes due 2020 (the Notes or Senior Notes). Our borrowing base under the revolving credit facility is $330 million. The borrowing base availability has been reduced by $3.1 million in conjunction with letters of credit issued to vendors at December 31, 2012, and by other limitations based upon a multiple of trailing earnings as defined in the credit facility. Our PV-10 at December 31, 2012, was $1,127 million, equivalent to two times our debt at such date, providing strong asset coverage for our indebtedness. We plan to maintain a capital structure that provides financial flexibility through the prudent use of leverage, aligning capital expenditures to cash flows and maintaining a strategic hedging program.

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Management and Technical Teams with Extensive Operational, Transactional and Financial Experience in the Energy Industry. With an average industry work experience of almost 30 years, our senior management team has considerable experience in acquiring, exploring, exploiting, developing and operating oil and gas properties, particularly in operationally intensive oil and gas fields. Three members of our executive management previously worked together as part of the senior management team of HS Resources, Inc., an independent oil and gas company that was listed on the New York Stock Exchange and primarily operated in the Denver-Julesburg Basin in northeast Colorado. HS Resources was acquired by Kerr-McGee Corporation in 2001 for $1.8 billion. We also employ more than 37 oil and gas technical professionals, including geophysicists, geologists, petroleum engineers and production and reservoir engineers, who have an average of approximately 18 years of experience in their respective technical fields. We continually leverage the extensive experience of our senior management and technical staff to benefit all aspects of our operations.

Summary Reserve Information

The following table presents summary information related to our estimated net proved reserves that are derived from our December 31, 2012, reserve report, which we prepared. Netherland, Sewell & Associates, Inc. (NSAI), independent petroleum engineers, audited all properties except the New Permian Properties.

	Estimated Net Proved Reserves at December 31, 2012 (MMBoe)				2012 Net Daily
	Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved	Production (Boe per day)
Aneth Field Properties	22.2	10.1	26.9	59.2	6,347
Wyoming Properties	2.3	1.2		3.5	1,539
Permian Properties	6.4	1.1	5.1	12.6	567
Bakken Properties	2.9		0.6	3.5	860
Total	33.8	12.4	32.6	78.8	9,313
Future operating costs ($ millions)				$ 1,861.0	
Future production taxes ($ millions)				807.2	
Future capital costs ($ millions)				832.0	
Future operating costs ($/Boe)				$ 23.62	
Future production taxes ($/Boe)				10.25	
Future capital costs ($/Boe)				10.56	

Description of Properties

Aneth Field Properties

Aneth Field, a giant legacy oil field in southeast Utah, holds 75% of our net proved reserves as of December 31, 2012, and accounted for 68% of our production during 2012, averaging 6,347 equivalent barrels of oil (Boe) per day, of which 97% was oil. During 2012, we completed 3 gross (2 net) wells. We own a majority of the working interests in, and are the operator of, three federal production units covering approximately 43,000 gross acres which constitute the Aneth Field Properties. These are the Aneth Unit, the McElmo Creek Unit and the Ratherford Unit, in which we own working interests of 65%, 71% and 62%, respectively, at December 31, 2012. We had interests in and operated 391 gross (260 net) producing wells and 328 gross (218 net) active water and CO_2 injection wells.

Aneth Field was discovered in 1956 by Texaco and has produced 429 million barrels (MMBbl) of oil to date. Aneth Field covers a single geologic structure with production coming from the Pennsylvanian age Desert Creek formation. For operational reasons, it was divided into three separate operating units, the Aneth Unit, the McElmo Creek Unit and the Ratherford Unit. In 1985, Mobil, as the operator of McElmo Creek Unit, initiated a successful CO_2 enhanced oil recovery project that has been in operation since then, resulting in significant incremental oil reserve production from the McElmo Creek Unit. While there is some reservoir heterogeneity in Aneth Field, development of the reserves generally has been accomplished with well-tested methodologies, including drilling and infilling vertical wells, horizontal drilling, waterflood activities and CO_2 flooding.

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The majority of our interests in the field were acquired through two separate transactions from each of Chevron Corporation and its affiliates (Chevron) and ExxonMobil Corporation (ExxonMobil), in 2004 and 2006, respectively. In November 2004, our predecessor company acquired a 53% operating working interest in the Aneth Unit, a 15% non-operating working interest in the McElmo Creek Unit and a 3% non-operating working interest in the Ratherford Unit from Chevron (the Chevron Properties). In April 2006, our predecessor company acquired an additional 7.5% working interest in the Aneth Unit, a 60% operating working interest in the McElmo Creek Unit and a 56% operating working interest in the Ratherford Unit from ExxonMobil (the ExxonMobil Properties). In each transaction, the remaining available interest was acquired by Navajo Nation Oil and Gas Company, which we refer to as NNOGC, in a strategic alliance that benefits both us and NNOGC. We have a Cooperative Agreement with NNOGC that outlines how future acquisitions in a defined area will be shared and divides responsibilities between the parties to assist in the efficient development of Aneth Field. Please read *Business and Properties Relationship with the Navajo Nation*.

In 2006, after becoming operator of the entire field, we began the infrastructure improvements required for us to expand the CO_2 flood to the Aneth Unit and began injecting CO_2 in 2007. Approximately 77 producing wells in the first three phases of this expansion are experiencing incremental oil production response due to the CO_2 flood. Production from the area covered by the first three phases of the Aneth CO_2 flood has increased by approximately 146% from 2006. During November 2011 we commenced injection of CO_2 in the Phase 4 area of the Aneth Unit CO_2 flood, and as of December 31, 2012, we were injecting CO_2 in approximately eighteen out of a total of 53 injection wells. During 2013, we anticipate completing additional infrastructure to substantially complete Phase 4 of the Aneth CO_2 infrastructure build out and expect to realize increasing oil production from the Phase 4 area in 2013 and beyond as a result.

The Aneth Unit CO_2 flood expansions are in the same field and producing formation as the existing McElmo Creek Unit CO_2 project. Initially, reserves associated with expansions are classified as proved undeveloped. Following installation of the necessary infrastructure, these CO_2-related reserves are reclassified as proved developed nonproducing reserves. Once a response is exhibited at a producing well, the reserves associated with that well are then reclassified to proved developed producing reserves. Within Aneth Field at December 31, 2012, we had estimated net proved reserves of 37 MMBoe that were classified as proved developed nonproducing or proved undeveloped. Of these reserves, 34.5 MMBoe are attributable to recoveries associated with expansions, extensions and processing of the tertiary recovery CO_2 floods in operation on the field.

Beyond realizing production growth from existing proved reserves, there are opportunities to increase proved reserves within Aneth Field through further expansion of the area under CO_2 flood and through technological improvements that may allow for greater recovery efficiency across the field. For example, we have not yet begun a CO_2 recovery program on the Ratherford Unit, which comprises approximately 30% of the total surface area of Aneth Field. Based on this unit s production history, geology and analogy to the existing CO_2 floods, we believe that the Ratherford Unit will respond favorably to CO_2 injection. However, no reserves were attributed to CO_2 recovery from this unit in our December 31, 2012, reserve report. Another opportunity for production growth from existing reserves lies within the IIC subzone of the Desert Creek formation (the DC IIC) in the McElmo Creek Unit, which we began recompleting in early 2010 with notable increases in production. This subzone was waterflooded by a previous operator, but was shut-in by the early 1980s due to high water cuts and low oil prices prevalent at the time, and has never been CO_2 flooded. As part of our work in the field we have determined that the DC IIC can be reactivated as a waterflood with highly economic results given today s commodity prices. Plans to implement a CO_2 flood in this zone are progressing as reservoir properties collected from the recompletions, such as deliverability, oil cut and reservoir pressure are analyzed. Meanwhile, we have begun the process of repressurizing this zone with water in preparation for CO_2 flooding. This recompletion and CO_2 flood project is expected to continue for several years, with further production increases expected. The project will require construction and rebuilding of infrastructure to accommodate the incremental injection and production. Planned activities in 2013 include recompleting 10 injecting and 10 producing wells.

CO_2 is available from McElmo Dome, the largest naturally occurring CO_2 source in the United States. McElmo Dome is operated by Kinder Morgan CO_2 Company, L.P. (Kinder Morgan), with whom we have a long-term contract, with CO_2 pricing based on a percentage of current NYMEX West Texas Intermediate (WTI) oil prices. Aneth Field is connected directly to McElmo Dome through a 28 mile pipeline that we operate and in which we owned a 71% interest at December 31, 2012. We believe our long-term contract with Kinder Morgan and our ownership and operatorship of the pipeline provide a high degree of certainty and visibility with regard to meeting our CO_2 supply needs. We are required to take, or pay for if not taken, 75% of the total of the maximum daily quantities for each month during the term of the Kinder Morgan contract. There are make-up provisions allowing any take-or-pay payments we make to be applied against future purchases for specified periods of time. We do not have the right to resell CO_2 required to be purchased under the Kinder Morgan contract. As of December 31, 2012, we had made no payments under this contract for CO_2 volumes for which we had not yet taken delivery.

Oil production from our Aneth Field is characterized as a light, sweet crude oil with an API gravity of 41 degrees. The field is connected by pipeline to a refinery located near Gallup, New Mexico, that is owned and operated by Western Refining Southwest, Inc. (Western), a subsidiary of Western Refining Inc. Western purchases all of our Aneth Field production under a contract that provides for a price equal to the NYMEX oil price minus a differential of $6.25 per barrel(Bbl) of oil. If, for any reason, Western is unable to process our oil, we have alternative access to markets through rail and truck facilities.

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Capital expenditures at Aneth Field during 2012 were approximately $64.1 million, representing 28% of our total capital expenditures, excluding acquisition expenditures, during this time period. Although the expansion of the CO_2 flood requires significant investments for infrastructure, wellhead equipment and CO_2 purchases, we expect that Aneth Field will continue to generate cash flow in excess of the cost of these requirements. We anticipate reinvesting this free cash flow in the development of our Bakken and Permian Properties, in our exploration-focused activities and, potentially, in other acquisition opportunities.

During the second quarter of 2012, we entered into two transactions regarding the Aneth Field Properties through which we and NNOGC consolidated our interests. In the first transaction, which closed in April, 2012, we entered into an agreement with affiliates of Denbury Resources Inc. (Denbury) pursuant to which we and NNOGC, on a 50%/50% basis, acquired a 13% working interest in the Aneth Unit and an 11% working interest in the Ratherford Unit for total cash consideration of $75 million (the Denbury Acquisition).

Contemporaneously with this transaction, we and NNOGC also entered into an amendment to our Cooperative Agreement. Among other changes, this amendment allowed NNOGC to exercise options to purchase 10% of our interest in Aneth Field, before giving effect to the Denbury transaction discussed above. This option was exercised for consideration of $100 million prior to customary closing adjustments. The purchase and sale agreement relating to the option exercise provided that the transaction be closed and paid for in two equal transfers in July 2012 and January 2013, each with an effective date of January 1, 2012. Each transfer was to be for 5% of our interest in the properties. We received a $10 million purchase deposit from NNOGC in April 2012, $5 million of which has reduced our capital investment in the Aneth Field Properties and $5 million of which is located on the balance sheet in other long term liabilities. The first transfer took place in July 2012 and the second transfer took place in January 2013.

The Cooperative Agreement amendment also provides for the cancellation of a second set of options held by NNOGC to purchase an additional 10% interest in the Aneth Field Properties and stipulates that NNOGC has one remaining option to purchase an additional 10% of our interest in the Aneth Field Properties (as it stood prior to the current option exercise and excluding the interest acquired from Denbury and certain other minority interests), exercisable in July 2017 at the then current fair market value of such interest.

The net effect of the acquisition of properties from Denbury and the sale of properties to NNOGC, following full consummation, is that our working interests in the Aneth Unit and the Ratherford Unit will remain essentially unchanged at 62% and 59%, respectively, and the working interest in the McElmo Creek Unit will be reduced from 75% to 67.5%.

The following table presents, as of December 31, 2012, our estimate of the future capital expenditures, net to our interest, for construction, well work and other costs and for purchases of CO_2 required to implement the CO_2 flood projects in two of the units of our Aneth Field Properties through 2045. The table also presents the estimated net proved developed non-producing and proved undeveloped reserves that we anticipate will be produced as a result of these projects, as included in our December 31, 2012 reserve report.

	Estimated Future Capital Expenditures	Estimated Future CO2 Purchases	Estimated Future Total Capital Expenditures	Estimated Reserves (MMBoe)	Estimated Future Development Cost ($/Boe)
	(in millions, except as otherwise indicated)				
Aneth Unit Phase 1, 2, 3 and 4 (PDNP)	$ 7.9	$ 114.3	$ 122.2	10.1	$ 12.11
Aneth Unit Phase 4 (PUD) and Plant	67.1	182.4	249.5	12.8	19.44
McElmo Creek Unit DC IIC and Plant	121.0	92.8	213.8	11.6	18.44
Total	$ 196.0	$ 389.5	$ 585.5	34.5	$ 16.96

Aneth Field Gas Compression. Currently there are two types of gas production in Aneth Field, saleable gas and gas that is contaminated by CO_2. The saleable gas stream has low levels of CO_2 while the contaminated gas stream has high levels of CO_2, which makes it unacceptable to gas purchasers. This contaminated gas stream, which is rich in valuable NGL and gas, is currently compressed and re-injected into the reservoir. As we continue our CO_2 injection and expansion plans, the volume of contaminated gas will significantly increase. During 2011, we completed rebuilding of the gas compression plant at Aneth Unit, which processes all contaminated gas from the expansion project. This plant dehydrates and recovers condensate from the recycled gas stream, and we plan to expand the plant to separate CO_2 and hydrocarbon gas as well. The hydrocarbon gas will be sold, adding income streams to the field economics while the separated CO_2 stream will be reinjected into the producing zone. The plant expansion is in the early stages of engineering design and is currently anticipated to be online in early 2015.

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Permian Properties

As of December 31, 2012, we had interests in 40,800 gross (17,100 net) acres in the Permian Basin of Texas and southeast New Mexico. Our position is divided between three principal project areas: the Wolfbone project area located in the Delaware Basin portion of the Permian Basin, primarily in Reeves County, the Wolfberry project area located in the Midland Basin portion of the Permian Basin, primarily in Howard, Martin, Midland and Ector counties and the Northwest Shelf project area located in the Denton, Gladiola and Knowles fields in the Northwest Shelf area in Lea County, New Mexico. During the year we completed 20 gross (13.6 net) wells in the Permian Properties and had 196 gross (110 net) producing wells at year end 2012. As of December 31, 2012, we had 1 gross (and net) well awaiting completion operations. During 2012, average net daily production from the Permian Properties was approximately 567 Boe and was 75% liquids. See *Business and Properties Marketing and Customers* for more information on how production from this area is sold. During 2013, we plan to participate in the drilling of 34 gross (11 net) wells on our Midland and Ector county properties and anticipate participating in the drilling of 10 gross (5 net) wells on our Howard County properties.

Wolfbone Project. We acquired an operated interest in the Wolfbone project during the second quarter of 2011. The Wolfbone project area includes approximately 24,000 gross acres in which we hold an approximate 34% interest. The primary objective of the Wolfbone development plan is the Wolfcamp formation with the Bone Spring formation serving as a secondary objective. Our current development plan calls for vertical well bores with between five and eight completion stages in the upper Wolfcamp and Third Bone Spring sand. At year-end 2011, gas gathering infrastructure did not yet exist in this project area and all gas produced from the wells was flared. We connected the wells to gathering infrastructure in the second quarter of 2012 and commenced gas and NGL sales at that time. Based on drilling activity to date, approximately 19% of the acreage is held by production.

Wolfberry Project. We acquired interests in the Wolfberry project from private companies in the third quarter of 2011 and the fourth quarter of 2012 as part of the Permian Acquisitions. The producing formations in our Wolfberry area extend over a 3,000 foot stratigraphic column and include the Mississippian, Strawn, Canyon, Cisco, Cline, Wolfcamp, Dean and Spraberry formations. The Wolfberry project comprises approximately 9,500 gross acres in which we have a 43% interest. The initial 2011 transaction was primarily an acquisition of proved reserves with seven producing wells and numerous opportunities for incremental development. The 2012 acquisitions included 1,300 net acres (non-operated working interest of approximately 39%) and 1,500 net acres (non-operated working interest of approximately 32%), respectively. Approximately 9.5 MMBoe of proved reserves are associated with our Wolfberry assets. We believe that growth potential exists from approximately 113 vertical drilling locations targeting the Wolfberry interval and 135 recompletion opportunities that are categorized as either proved or probable. We also believe that potential upside exists from the multi-pay, multi-play nature of the area, which is prospective for horizontal development in the Wolfcamp and Cline formations. The acreage is largely held by production and we estimate that a one-rig program for two years will hold all of the acquired leases.

Northwest Shelf Project. In the fourth quarter of 2012, we acquired assets in Lea County, New Mexico in the Denton, Gladiola and Knowles Fields, which are legacy conventional oil fields that produce from fractured carbonate reservoirs and cover 4,700 gross acres in which we hold an approximate 85% working interest, all held by production. Our interest in Denton Field, the largest of the three fields, consists of 2,900 gross acres, all of which are held by production. Approximately 1.4 MMBoe of proved reserves are associated with our Denton Field interests. We believe that growth potential and upside may exist from activities such as deepening existing wells and infill drilling from 40-acre to 20-acre spacing. We are the operator of the Lea County assets.

Other assets. Other assets acquired during the fourth quarter of 2012 are a combination of conventional and unconventional producing properties in the Permian Basin. The acquired assets comprise 2,600 gross acres in which we hold an approximate 40% working interest, all held by production. Approximately 0.8 MMBoe of net proved reserves are associated with these assets at December 31, 2012.

Bakken Properties

As of December 31, 2012, we had interests in approximately 88,100 gross (32,500 net) acres in the Bakken shale trend of the Williston Basin in North Dakota. We have two principal project areas: the New Home project area located in Williams County, comprising approximately 22,900 net acres and the Paris project area located in McKenzie County, comprising approximately 9,400 net acres. We also have interests in various smaller project areas, which in total comprise approximately 200 net acres, primarily in McKenzie County. During 2012, average daily production from the Bakken Properties was approximately 860 Boe and was 97% liquids. As of December 31, 2012, we had interests in 58 gross (14 net) producing wells. During 2012, we participated in the completion of 31 gross (6.6 net) wells associated with the Bakken Properties and had an additional 4 gross (1.1 net) wells waiting on completion at year-end. See *Business and Properties Marketing and Customers* for more information on how production from the Bakken Properties is sold. In 2013, we plan to participate in the drilling and completion of 3 gross (0.8 net) wells in the New Home project area.

New Home Project. We acquired our interest in the New Home project area in 2010 through a joint venture with Halcón Resource Corporation (Halcón), formerly GeoResources, Inc. In total, the New Home project area includes 69,000 gross leasehold acres, in which we have an average 33% working interest. Based on drilling activity to date, approximately 53% of the acreage is considered developed and 71% is held by production.

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The primary objective of the New Home development plan is the Bakken shale formation with a secondary objective of the Three Forks formation, which lies below the lower Bakken shale. All of our wells are currently producing from the Middle Bakken. While we have not tested the Three Forks formation, it is productive in other portions of Williams and McKenzie counties. The wells in this area are vertically drilled to a target depth, at which point the drill bit is steered and drilled horizontally through the target formation. A typical well in this area has a horizontal length of 10,000 feet and is completed using hydraulic fracturing with between 30 and 38 stages.

Paris Project. We acquired our interest in the Paris project area through a farmout from Marathon Oil Company. The Paris project area covers approximately 19,100 gross leasehold acres in which we have an average 49% working interest. We are the operator of the Paris project and do not face meaningful lease expirations until 2014.

Wyoming Producing Properties

Hilight Field is located in the Powder River Basin in Campbell County, Wyoming, and consists of the Jayson Unit, the Grady Unit and the Central Hilight Unit. Hilight Field was discovered by Inexco Oil Company in 1969, unitized in 1971 and 1972, and underwent waterflood between 1972 and the mid-1990s. We have an 82.7% working interest in the Jayson Unit, an 82.5% working interest in the Grady Unit and a 98.5% working interest in the Central Hilight Unit. The Jayson, Grady and Central Hilight units cover an area of almost 50,000 gross acres. Our predecessor company acquired Hilight Field as part of a corporate acquisition in 2008 and initial activities were primarily based on production from the unitized Muddy formation, which generates free cash flow due to low reinvestment requirements. We have an inventory of low risk re-stimulation and infill drilling projects which we expect will moderate the natural decline of this field.

As of December 31, 2012, there were 157 gross (149 net) producing wells, excluding shut-in coalbed methane wells, and gross cumulative production through December 31, 2012, from our three operated units was 68.5 MMBbl of oil and 150 billion cubic feet of gas. During 2012, production from Hilight Field averaged 1,529 Boe per day and was 16% oil.

In Hilight Field, we are conducting geologic work including a 3-D seismic survey focused on prospective oil-bearing formations located in intervals other than the Muddy formation. These other formations include the Mowry, Turner, Niobrara and Minnelusa. Our 45,000 net acres in Hilight Field are held by production, which provides us flexibility in terms of pursuing development of these formations. In recent years, the Powder River Basin has experienced a resurgence in drilling activity focused on these formations as operators apply new technology, including horizontal drilling and multi-stage hydraulic fracturing, to previously bypassed formations. Several operators have experienced successful drilling results in the Turner formation in areas near our leasehold position, as well as in the Niobrara formation. During 2012, we successfully recompleted nine vertical wells with single-stage fracs in the Mowry formation and refraced six Muddy formation wells.

Exploration Focused Properties

Within our exploration portfolio, we own leases covering approximately 76,400 net acres in the Big Horn Basin, which may be prospective for production from multiple formations, including the Mowry, Frontier and Phosphoria. As of December 31, 2012, we had recompleted one vertical well with a single-stage frac in the Mowry shale and drilled and completed a horizontal well. Our horizontal well, the Schuster Flats 14-27-47-94H, does not appear to have encountered economic quantities of hydrocarbons and is currently shut-in. We are, however, continuing to evaluate the potential for future exploration activity on our acreage in the basin. We do not face significant lease expirations in this area prior to 2015.

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Estimated Net Proved Reserves

The following table presents our estimated net proved oil, gas and NGL reserves and the present value of our estimated net proved reserves as of December 31, 2012, 2011 and 2010 according to Securities and Exchange Commission (SEC) standards. The standardized measure shown in the table below is not intended to represent the current market value of our estimated oil and gas reserves.

	Year Ended December 31,		
	2012	2011	2010
Net proved developed reserves			
Oil (MBbl)	39,288	32,347	30,818
Gas (MMcf)	25,568	17,523	13,968
NGL (MBbl)	2,668	1,603	1,165
MBoe (1)	46,217	36,871	34,312
Net proved undeveloped reserves			
Oil (MBbl)	23,269	20,494	19,414
Gas (MMcf)	22,153	17,634	25,130
NGL (MBbl)	5,596	4,494	6,754
MBoe (1)	32,557	27,927	30,357
Total net proved reserves			
Oil (MBbl)	62,557	52,841	50,232
Gas (MMcf)	47,721	35,157	39,098
NGL (MBbl)	8,264	6,097	7,919
MBoe (1)	78,774	64,798	64,669
PV-10 ($ in millions) (2)(3)	$ 1,127	$ 1,143	$ 848
Discounted future income taxes ($ in millions)	(255)	(327)	(261)
Standardized measure ($ in millions) (2)(4)	$ 872	$ 816	$ 587

1) Boe is determined using one Bbl of oil or NGL to six Mcf of gas.
2) In accordance with SEC and Financial Accounting Standards Board (FASB) requirements, our estimated net proved reserves and standardized measure at December 31, 2012, were determined utilizing prices equal to the 2012 twelve-month unweighted arithmetic average of first day of the month prices, resulting in an average NYMEX oil price of $94.71 per Bbl and an average Henry Hub spot market gas price of $2.76 per one million British thermal units (MMBtu).
3) PV-10 is a non-GAAP measure and incorporates all elements of the standardized measure, but excludes the effect of income taxes. Management believes that pre-tax cash flow amounts are useful for evaluative purposes since future income taxes, which are affected by a company s unique tax position and strategies, can make after-tax amounts less comparable.
4) Standardized measure is the present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC and FASB, less future development costs and production and income tax expenses, discounted at a 10% annual rate to reflect the timing of future net revenue. Calculation of standardized measure does not give effect to derivative transactions. For a description of our derivative transactions, please read *Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk.*

The data in the above table represent estimates only. Oil and gas reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate present value, which is required by SEC and FASB pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to the timing of future production, which may prove to be inaccurate. The accuracy of any reserves estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserves estimates may vary, perhaps significantly, from the quantities of oil and gas that are ultimately recovered.

As an operator of domestic oil and gas properties, we are required to file Department of Energy Form EIA-23, Annual Survey of Oil and Gas Reserves, as required by Public Law 93-275. There are differences between the reserves as reported on Form EIA-23 and as reported herein, largely attributable to the fact that Form EIA-23 requires that an operator report on the total reserves attributable to wells that it operates, without regard to ownership (i.e., reserves are reported on a gross operated basis, rather than on a net interest basis).

Producing oil and gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Therefore, without reserve additions in excess of production through successful exploitation and development activities or acquisitions, our reserves and production will ultimately decline over time. Please read *Risk Factors Risks Related to Our Business, Operations and Industry* and *Note 12 Supplemental Oil and Gas Information (unaudited)* to the audited consolidated financial statements for a discussion of the risks inherent in oil and gas estimates and for certain additional information concerning our estimated proved reserves.

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Proved Developed and Undeveloped Reserves. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled within five years from known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

A significant portion of our proved undeveloped reserves are associated with large CO_2 flood projects in the Aneth and McElmo Creek Units that require significant capital investments over several years of development. These undeveloped CO_2 flood projects comprised approximately 75% of our proved undeveloped reserves at December 31, 2012. Facility construction and well development activities began on these projects in 2006, with CO_2 injection commencing in 2007, and remain ongoing. During 2012, we transferred approximately 2.0 MMBoe of Aneth Field reserves to proved developed producing status from the proved undeveloped and proved non-producing categories as a result of continued CO_2 response and continued Phase 4 Aneth CO_2 infrastructure construction.

During 2012 we acquired 4.3 MMBoe of proved undeveloped reserves related to the Permian Acquisitions and added 2.8 MMBoe of undeveloped reserves as a result of adding drilling offset locations. Additionally during 2012, we transferred 2.4 MMBoe and 1.5 MMBoe of proved undeveloped reserves to proved developed producing status in our Bakken and Permian properties, respectively.

With respect to the properties included in our prior year reserve reports, we incurred development costs of $100.6 million in 2012 as compared to the $77.2 million incurred in 2011. The increase was primarily due to $23.5 million in drilling and completion costs in the Bakken Properties in 2012 compared to no developmental drilling in 2011. Future development costs associated with the New Permian Properties were $82.5 million at December 31, 2012

At December 31, 2012, no proved undeveloped reserves have remained undeveloped for more than five years.

Changes in Proved Reserves

Proved reserves reported by us of 78.8 MMBoe at December 31, 2012 increased from the 64.8 MMBoe reported at December 31, 2011. Production during 2012 reduced proved reserves by 3.4 MMBoe, net revisions of previous estimates increased proved reserves by 1.8 MMBoe and extensions and discoveries increased proved reserves by 4.9 MMBoe. Purchases of reserves in place increased proved reserves by 13.4 MMBoe while sales of reserves decreased proved reserves by 2.7 MMBoe. In accordance with SEC requirements, the reserves at December 31, 2012, utilized prices (subsequently adjusted for quality and basis differentials) of $94.71 per Bbl of oil and $2.76 per MMBtu of gas, as compared to prices of $96.19 per Bbl of oil and $4.12 per MMBtu of gas at December 31, 2011.

Controls Over Reserve Report Preparation, Technical Qualification and Methodologies Used

We prepared reserve estimates as of December 31, 2012. NSAI, our independent petroleum engineers, audited all properties except the New Permian Properties. Please read *Risk Factors Risks Related to Our Business, Operations and Industry* in evaluating the material presented below.

Our reserve report was prepared under the direct supervision of the Company s Reservoir Engineering Manager, Mr. Paul J. Taylor. Mr. Taylor has more than 26 years of experience in the oil and gas industry including engineering, business development and economic analysis. During his career, Mr. Taylor has worked in Alaska, California, Texas, the United Kingdom and the Middle East, has experience with nearly all forms of primary, secondary and tertiary recovery methods and has worked onshore, shallow water and deep water projects. Mr. Taylor has a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines, a Master of Science in Energy Economics from the University of Wisconsin-Madison and is a Professional Petroleum Engineer in Colorado and Alaska. His qualifications also meet or exceed the qualifications of reserve estimators and auditors set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The reserve report is based upon a review of property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, geoscience and engineering data, and other information as prescribed by the SEC. The reserve estimates are reviewed internally by Resolute s senior management prior to an audit of the reserve estimates by NSAI. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis, advanced production type curve matching, volumetrics, material balance, petrophysics/log analysis and analogy reservoir simulation. Some combination of these methods is used to determine reserve estimates in substantially all of our areas of operation.

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NSAI is a worldwide leader of petroleum property analysis to industry and financial organizations and government agencies. With offices in Dallas and Houston, NSAI delivers high quality, fully integrated engineering, operational, geologic, geophysical, petrophysical and economic solutions for all facets of the upstream energy industry. Within NSAI, the technical person primarily responsible for the NSAI audit is David Miller. Mr. Miller has been practicing consulting petroleum engineering at NSAI since 1997. He is a Registered Professional Engineer in the State of Texas and has more than 31 years of practical experience in petroleum engineering, with more than 15 years of experience in the estimation and evaluation of reserves. He graduated from the University of Kentucky in 1981 with a Bachelor of Science degree in Civil Engineering and from Southern Methodist University in 1994 with a Master of Business Administration degree. Mr. Miller 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; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

We requested that NSAI audit the estimates of proved reserves for all properties owned by us at December 31, 2012, except for the New Permian Properties. Based upon the estimates prepared by us, the reserve audit conducted by NSAI addresses 88% of the total net equivalent MBoe proved reserve quantities and 87% of the PV-10. A report of NSAI regarding its audit of the estimates of proved reserves at December 31, 2012, has been filed as Exhibit 99.1 to this report and is incorporated herein.

Production, Price and Cost History

The table below summarizes our operating data for 2012, 2011 and 2010.

	Year Ended December 31,(1)		
	2012	**2011**	**2010**
Sales Data:			
Oil (MBbl)	2,773	2,298	2,089
Gas and NGL (MMcfe)	3,811	3,755	3,843
Combined volumes (MBoe)	3,409	2,924	2,730
Daily combined volumes (Boe per day)	9,313	8,012	7,478
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$ 86.70	$ 77.60	$ 73.22
Gas and NGL ($/Mcfe)	4.68	6.13	5.32
Average Production Costs ($/Boe):			
Lease operating expense	$ 23.45	$ 20.35	$ 18.91
Production and ad valorem taxes	10.48	10.73	8.85

1) The Aneth Field Properties comprised a majority of our total proved reserves as of December 31, 2012. Production from the Aneth Field Properties was 2,262 MBbl and 364 MMcfe in 2012, 2,103 MBbl and 504 MMcfe in 2011 and 1,944 MBbl and 482 MMcfe in 2010.

Oil and Gas Wells

The following table sets forth information as of December 31, 2012, relating to the productive wells in which we own a working interest. A well with multiple completions in the same bore hole is considered one well. Wells are considered oil or gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion. Productive wells consist of producing wells and wells capable of producing, including wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have a working interest and net wells are the sum of our working interests owned in gross wells. In addition to the wells below, we had interests in and operated 332 gross (222 net) active water and CO_2 injection wells as of December 31, 2012.

	Productive Wells(1)	
	Gross	**Net**
Oil	798	532
Gas	173	157

Total	971	689

1) We operated 808 gross (643 net) productive wells at December 31, 2012.

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Drilling Activity

The following table sets forth information with respect to development and exploration wells we completed during 2012, 2011 and 2010. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells. Fluid injection wells for waterflood and other enhanced recovery projects are not included as gross or net wells.

	Year Ended December 31,		
	2012	2011	2010
Gross development wells:			
Productive [1]	20		
Dry [2]			
Total development wells	20		
Gross exploratory wells:			
Productive [1]	43	17	1
Dry [2]			
Total exploratory wells	43	17	1
Total gross wells drilled	63	17	1

	Year Ended December 31,		
	2012	2011	2010
Net development wells:			
Productive [1]	12		
Dry [2]			
Total development wells	12		
Net exploratory wells:			
Productive [1]	12	7	1
Dry [2]			
Total exploratory wells	12	7	1
Total net wells drilled	24	7	1

1) A productive well is a well we have cased. Wells classified as productive do not always result in wells that provide economic production.
2) A dry well is a well that is incapable of producing oil or gas in sufficient quantities to justify completion.

Acreage

All of our leasehold acreage is categorized as developed or undeveloped. The following table sets forth information as of December 31, 2012, relating to our leasehold acreage.

Area	Developed Acreage (1) Gross (2)	Net (3)
Hilight Field (WY)	49,608	45,421
Aneth Field (UT)	43,218	28,122
North Dakota	43,943	16,072
Permian Basin (TX)	13,463	5,697
Permian Basin (NM)	4,690	3,971
Hilight area non-unit acreage (WY)	960	960
Big Horn Basin (WY)	400	400
Total	156,282	100,643

Area	Undeveloped Acreage (4) Gross (2)	Net (3)
Big Horn Basin (WY)	87,060	76,439
Black Warrior Basin (AL)	28,941	21,113
North Dakota	44,145	16,377
Permian Basin (TX)	22,664	7,382
Other non-unit acreage	800	800
Total	183,610	122,111

1) Developed acreage is acreage attributable to wells that are capable of producing oil or gas.
2) The number of gross acres is the total number of acres in which we own a working interest and/or unitized interest.
3) Net acres are calculated as the sum of our working interests in gross acres.
4) Undeveloped acreage includes leases either within their primary term or held by production.

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Approximately 21,200 net acres, 9,900 net acres and 46,400 net acres of undeveloped acreage expire in 2013, 2014 and 2015, respectively. Approximately 13,500 net acres that expire in 2013 relate to acreage in the Black Warrior Basin in Alabama to which no proved reserves were assigned in our December 31, 2012, reserve report. All costs associated with the Black Warrior Basin have been transferred to proved oil and gas properties and are subject to amortization. Approximately 39,600 net acres that expire in 2015 relate to acreage in the Big Horn Basin in Wyoming to which no proved reserves were assigned in our December 31, 2012, reserve report.

Present Activities

As of December 31, 2012, we were in the process of drilling 5 gross (1.1 net) wells and there were 5 gross (2.1 net) wells waiting on completion operations. Please read *Business and Properties* *Descriptions of Properties* for additional discussion regarding our present activities.

Relationship with the Navajo Nation

The purchase of our Aneth Field Properties was facilitated by our strategic alliance with NNOGC and, through NNOGC, the Navajo Nation. The Navajo Nation formed NNOGC, a wholly-owned corporate entity, under Section 17 of the Indian Reorganization Act. We supply NNOGC with acquisition, operational and financial expertise and NNOGC helps us communicate and interact with the Navajo Nation agencies.

Our strategic alliance with NNOGC is embodied in a Cooperative Agreement consummated with NNOGC and our predecessor company in 2004 to facilitate our joint acquisition of the Chevron Properties. The agreement was amended subsequently to facilitate the joint acquisition of the ExxonMobil Properties and was amended again in conjunction with the sale of 10% of our interest in Aneth Field to NNOGC in the second quarter of 2012. Among other things, this agreement provides that:

- We and NNOGC will cooperate on the acquisition and subsequent development of our respective properties in Aneth Field.

- NNOGC will assist us in dealing with the Navajo Nation and its various agencies, and we will assist NNOGC in expanding its financial expertise and operating capabilities. Since acquisition of the Aneth Field Properties, NNOGC has helped facilitate interaction between the Company and the Navajo Nation Minerals Department and other agencies of the Navajo Nation.

- NNOGC has a right of first negotiation in the event of a proposed sale or change of control of Resolute or a sale by Resolute of all or substantially all of its Chevron or ExxonMobil Properties. This right is separate from and in addition to the statutory preferential purchase right held by the Navajo Nation.

In addition to these provisions, NNOGC was granted three separate but substantially similar purchase options. Each purchase option entitled NNOGC to purchase from us up to 10% of the undivided working interests that we acquired from Chevron or ExxonMobil, as applicable, as to each unit in the Aneth Field Properties (each a Purchase Option). The Cooperative Agreement amendment executed in 2012 provides for the cancellation of the second Purchase Option and stipulates that NNOGC has one remaining Purchase Option (as it stood prior to the current option exercise and excluding the interest acquired from Denbury and certain other minority interests). The remaining Purchase Option is exercisable in July 2017 at the then current fair market value of such interest. The exercise by NNOGC of its Purchase Option in full would not give it the right to remove us as operator of any of the Aneth Field Properties.

Marketing and Customers

Aneth Field. We currently sell all of our oil from our Aneth Field Properties to Western under a purchase agreement dated August 2011, which provides for a fixed differential to the NYMEX price for oil of $6.25 per Bbl, with future adjustments to reflect any increase in transportation costs from the field to the refinery. The agreement covers up to 8,000 combined barrels per day of our and NNOGC volumes (the Base Volume) and an additional volume of up to 3,000 barrels per day (the Additional Volume). The agreement contains a two year term for the Base Volume and a six month term for the Additional Volume, each commencing on August 1, 2011. Both continue automatically on a month-to-month basis after expiration of the initial term unless terminated by either party with 180 day prior written notice (120 days for the Additional Volume). The agreement may also be terminated by Western upon sixty days notice, if Western s right-of-way agreements with the Navajo Nation are declared invalid and either Western is prevented from using such rights-of-way or the Navajo Nation declares Western to be in trespass with respect to such rights-of-way.

Western refines our oil at their 26,000 barrel per day refinery in Gallup, New Mexico. Our production is transported to the refinery via the Running Horse oil pipeline owned by NNOGC to its Bisti terminal, approximately 20 miles south of Farmington, New Mexico, that serves the refinery. Our and NNOGC s oil has been jointly marketed to Western. The combined Resolute and NNOGC volumes were approximately 9,100 barrels of oil per day as of year-end.

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The Aneth Field oil is a sweet, light crude oil that is well suited to be refined in Western s refinery. Although we have sold all of our oil production to Western since acquiring the Chevron Properties in November 2004, and despite the value of our oil production to Western, we cannot be certain that the commercial relationship with Western will continue for the indefinite future and that the refinery will not suffer significant down-time or be closed. If for any reason Western is unable or unwilling to purchase our oil production, we have other production marketing alternatives. We have the ability to load up to 3,000 barrels per day at Western s Gallup refinery rail loading site in the event that Western is unable to process or otherwise does not take our oil volumes. NNOGC has completed construction of a high volume truck loading facility located at the terminal end of NNOGC s Running Horse pipeline that is capable of loading all of our and NNOGC s production. We have life-of-lease access to the truck loading facility pursuant to an agreement with NNOGC. Oil can be trucked a relatively short distance from the loading facility to rail loading sites near and south of Gallup, New Mexico, or longer distances to refineries or oil pipelines in southern New Mexico and west Texas. We can also transport our oil by various combinations of truck, pipeline and rail from the Aneth Field Properties to markets north in Utah, Colorado and Wyoming. The cost of selling our oil to alternative markets in the short term would result in a greater differential to the NYMEX price of oil than we currently receive. If we choose or are forced to sell to these alternative markets for a longer period of time, these costs could be lowered significantly. Under long term arrangements, which may require the investment of capital, we believe we would realize a NYMEX differential substantially equivalent to the current differential realized in the price received from Western.

Our Aneth Field gas production is minimally processed in the field and, until recently, was sent via pipeline to the San Juan River Gas Plant for further processing. In December 2012 we received a force majeure notice from Anadarko Petroleum Corporation (Anadarko), the owner of the plant, notifying us that the gas pipeline between our field and the San Juan River Gas Plant would be shut down for an unspecified period of time because of a leak and potentially extensive corrosion. Since then we have been flaring our gas so that production of oil in the field can continue, but have been installing minor facility connections so that the flared gas can be reinjected into the field. These facilities should be operational within the next thirty days. We are also negotiating with Anadarko and the owners of another plant, known as the Lisbon Plant, for an alternative processing and sales arrangement through the Lisbon Plant. We currently expect to be able to begin sales through the Lisbon Plant in the next ninety days. We expect that the sales through the new plant would continue to be based on a contractually specified percentage of the proceeds from the sale of gas and NGL.

Texas. In Reeves County, we sell all of our oil to Western. The contract specifies that the price paid to us is the sum of the Base Price (average daily NYMEX settlement price plus or minus the roll component), plus or minus the differential between Argus reported Midland WTI and Cushing WTI, and a transportation differential of $3.80 per Bbl.

Southern Union Gas Services (Southern Union) purchases substantially all of our Reeves County gas and processes it at Southern Union s JAL No. 3 Plant Area system. The contract has a seven year term and is a percent-of-proceeds agreement that nets us 87% of the value of NGL and residual gas sales, less certain transportation and fractionation fees. The prices paid by Southern Union to us for NGL are based on the monthly average of the daily price for NGL components quoted in the Oil Price Information Service for Mont Belvieu Spot Gas Liquids Prices, less transportation and fractionation fees. The price paid for residue gas is the index posting for Midpoint: Permian Basin Area for El Paso Natural-Permian Basin published in Platt s Gas Daily.

In Martin and Howard counties, we sell our oil to Plains Marketing, LP (Plains) and Enterprise Crude Oil LLC (Enterprise). The Plains contract is a month-to-month agreement that calls for the price paid by Plains to us to equal the sum of (a) the Plains WTI crude oil posting for the month, plus or minus (b) the Argus P-plus weighted average for the month of delivery, plus or minus (c) the differential between Argus reported Midland WTI and Cushing WTI, less a transportation differential of $2.50 per Bbl. Under the Enterprise contract we receive the Enterprise WTI crude oil posted price, plus the Argus P-plus monthly average, plus the Argus WTI Midland Cushing differential, minus $2.50 per Bbl in transportation.

Gas produced in Martin and Howard counties is gathered by and sold to WTG Gas Processing, LP (WTG) under a percent-of-proceeds contract that nets us 88% of NGL and residual gas sales, less certain transportation and fractionation fees. The prices paid by WTG to us for NGL is based on the monthly average of the daily midpoint price for NGL components quoted in the Oil Price Information Service for Mont Belvieu Spot Gas Liquids Prices. The price paid for residue gas is the index posting for El Paso Natural Gas Company-Permian Basin published in Inside FERC Gas Market Report. The contract has a five-year term that expires in early 2014 and then continues on a year-to-year basis thereafter.

Non-operated oil and gas produced in Midland, Ector and Howard counties is currently being marketed by the operators of the properties.

New Mexico. The majority of oil produced in Lea County, New Mexico and Dawson and Yoakum counties in Texas is sold to Genesis Crude Oil (Genesis) and LPC Crude Oil, Inc (LPC). The price received under the Genesis contract is determined by taking the monthly average for Plains posted price for WTI crude, plus the trade month average of the midpoint of the Platt s US spot crude assessment for WTI, plus the differential at Cushing (P-Plus), plus the trade month average of the difference in the midpoints of the Platt s US spot crude assessments for West Texas Sour at Midland and WTI at Cushing, minus $4.02 per Bbl for transportation. The price received under the LPC contract is the Plain s posted price for WTI, plus the Argus posted differentials plus weighted average for the month of delivery quoted in Argus Americas Crude Oil Assessments during the period beginning with the 26th day of the month that is two months prior to the month of delivery, plus the WTI weighted average differential for the month of delivery in Argus, plus the Argus Midland/Cushing differential during the period beginning with the 26th day of the month two months prior to delivery through and including the 25th day of the month that is immediately prior to the month of delivery, minus $3.45 per Bbl for transportation.

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North Dakota. We currently sell our net working interest share of oil produced from the New Home area in Williams County, North Dakota through the project s operator, Halcón. In 2011, Halcón entered into a oil gathering agreement with Banner Transportation Company, LLC (Banner). We, Halcón and other working interest owners have agreed to commit all oil volumes produced at New Home for a period of ten years to Banner s planned Market Center Gathering System to be constructed in eastern Montana and western North Dakota. As of year-end 2012, 27 out of 36 producing wells were connected to the oil gathering system. We anticipate that all wells in New Home will be connected to the Banner gathering system. Halcón further markets the oil through a month-to-month purchase agreement with Plains Marketing, LP (Plains). The contract price is based on the average daily WTI prompt month settlement price as traded for the calendar month of delivery, minus the Clearbrook, Minnesota, sweet crude differential, minus transportation costs.

We currently sell our working interest share of gas produced from the New Home area in Williams County, North Dakota through Halcón. In 2011, Halcón entered into a gas sales agreement with Hiland Partners, LLC (Hiland). As of year-end 2012, 32 out of 36 producing wells were connected to the gas gathering and sales system. We anticipate that all wells in New Home will be connected to the Hiland system. We receive a percentage of proceeds for the gas and NGL processed and sold by Hiland based on an index price from Northern Natural Gas Company located in Ventura, Iowa, after deducting transportation and other applicable fees.

Wyoming. We sell the majority of our oil in Wyoming to Enterprise and minor amounts to other purchasers in a competitive market. The price we receive relative to the NYMEX price varies depending on supply and demand differentials in the relevant geographic areas in which our wells are located and the quality of our oil. Our conventional gas in Wyoming comes from Hilight Field and is sold to an affiliate of Anadarko s Hilight Gas Plant. We receive a percentage of proceeds for the NGL sold by the plant, and we can either take our residue gas in kind or market it through Anadarko. We are currently selling our gas through Anadarko and receive the Colorado Interstate Gas Company index price after deducting differentials and transportation costs for all the gas we sell.

Derivatives. We enter into derivative transactions from time to time with unaffiliated third parties for portions of our oil and gas production to achieve more predictable cash flows and to reduce exposure to short-term fluctuations in oil and gas prices. Such third parties must be a member of our credit facility. For a more detailed discussion, please read *Management s Discussion and Analysis of Financial Condition and Results of Operations.*

Other Factors. The market for our production depends on factors beyond our control, including domestic and foreign political conditions, the overall level of supply of and demand for oil and gas, the price of imports of oil and gas, weather conditions, the price and availability of alternative fuels, the proximity and capacity of transportation facilities and overall economic conditions. The oil and gas industry as a whole also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Aneth Gas Processing Plant

We have an interest in gas gathering and compression facilities located within and adjacent to our Aneth Field Properties. Collectively called the Aneth Gas Processing Plant, the facility consists of: a) an active gas compression operation currently operated by us and b) a substantially dismantled gas processing facility for which Chevron remains the operator of record. In 2006, Chevron began the process of demolishing the inactive portions of the Aneth Gas Processing Plant. It continues to manage the project, and it retains a 39% interest in all demolition and environmental clean-up expenses. We acquired ExxonMobil s 25% interest in the decommissioned plant and are responsible for that portion of decommissioning and cleanup costs. Activities performed to date include removal of asbestos-containing building and insulation materials, partial dismantling of inactive gas plant buildings and facilities and limited remediation of hydrocarbon-affected soil.

As of December 31, 2012, we estimate the total cost to fully decommission the inactive portion of the Aneth Gas Processing Plant site to be $26.3 million, of which approximately $25.5 million had already been incurred and paid for. We have recorded an asset retirement obligation for the remaining demolition liability net to our interest of $0.2 million at December 31, 2012. Demolition activities were substantially complete at December 31, 2012, and are scheduled to be concluded in 2013. These costs do not include any costs for clean-up or remediation of the subsurface. The Aneth Gas Processing Plant site was previously evaluated by the Environmental Protection Agency (EPA) for possible listing on the National Priorities List (NPL), of sites contaminated with hazardous substances with the highest priority for clean-up under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA). Based on its investigation, the EPA concluded no further investigation was warranted and that the site was not required to be listed on the NPL. The Navajo Nation Environmental Protection Agency (Navajo Nation EPA) now has primary jurisdiction over the Aneth Gas Processing Plant site. We cannot predict whether Navajo Nation EPA will require further investigation and possible clean-up, and the ultimate clean-up liability may be affected by the Navajo Nation s recent enactment of a Navajo CERCLA statute. The Navajo CERCLA statute, in some cases, imposes broader obligations and liabilities than the federal CERCLA. We have been advised by Chevron that a significant portion of the subsurface clean-up or remediation costs, if any, would be covered by an indemnity from the prior owner of the plant, and Chevron has provided us with a copy of the pertinent purchase agreement that appears to support its position. We cannot predict, however, whether any subsurface remediation will be required or what the cost of this clean-up or remediation could be. Additionally, we cannot be certain whether any of such costs will be reimbursable to us pursuant to the indemnity of the prior owner. Please read *Business and Properties Environmental, Health and Safety Matters and Regulation Waste Handling*.

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Title to Properties

Producing Property Acquisitions

We believe we have satisfactory title to all of our material proved properties in accordance with standards generally accepted in the industry. Prior to completing an acquisition of proved hydrocarbon leases we perform title reviews on the most significant leases, and, depending on the materiality of properties, we may obtain a new title opinion or review previously obtained title opinions.

In connection with our acquisition of the Chevron and ExxonMobil Properties, we obtained attorneys title opinions showing good and defensible title in the seller to at least 80% of the proved reserves of the acquired properties as shown in the relevant reserve reports presented by the sellers. We also reviewed land files and public and private records on substantially all of the acquired properties containing proved reserves. We performed similar title and land file reviews prior to acquiring the Wyoming Properties; however, the prior title opinions available for us to review and update constituted 62% of the proved reserves of the acquired properties. We reviewed attorney title opinions and public records covering 100% and 82% of the proved reserves related to Martin and Howard counties in Texas, respectively. Additionally, we reviewed 98% of the title opinions and public records related to the proved reserves in Lea County, New Mexico and 100% of the proved reserves related to Ector and Midland counties in Texas.

The Aneth Field Properties are subject to a statutory preferential purchase right for the benefit of the Navajo Nation to purchase at the offered price any Navajo Nation oil and gas lease or working interest in such a lease at the time a proposal is made to transfer the lease or interest. This could make it more difficult to sell our oil and gas leases and, therefore, could reduce the value of the Aneth Field leases if we attempt to sell them.

Non-Producing Leasehold Acquisitions

We participate in the normal industry practice of engaging consulting companies to research public records before making payment to a mineral owner for non-producing leasehold. Prior to drilling a well on these properties, a title attorney is engaged to give an opinion of title.

Our properties are also subject to certain other encumbrances, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and gas industry. We believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or will materially interfere with the intended operation of our business.

Competition

Competition is intense in all areas of the oil and gas industry. Major and independent oil and gas companies actively bid for desirable properties, as well as for the equipment and labor required to operate and develop such properties. Many of our competitors have financial and personnel resources that are substantially greater than our own and such companies may be able to pay more for productive properties and to define, evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Seasonality

Our operations have not historically been subject to seasonality in any material respect.

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Environmental, Health and Safety Matters and Regulation

General. We are subject to various stringent and complex federal, tribal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment, and protection of human health and safety. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences or other operations are undertaken;
- require the installation and operation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, production, transportation and processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate pollution from historical and ongoing operations, such as the closure of pits and plugging of abandoned wells, and the remediation of releases of oil or other substances; and
- require preparation of an Environmental Assessment and/or an Environmental Impact Statement.

These laws and regulations may also restrict the rate of oil and gas production to a level below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunctive action, as well as administrative, civil and criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that may be adopted in the future, could have a material adverse impact on our business, financial condition and results of operations.

We believe our operations are in substantial compliance with all existing environmental, health and safety laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. Spills or unpermitted releases may occur, however, in the course of our operations. There can be no assurance that we will not incur substantial costs and liabilities as a result of such spills or unpermitted releases, including those relating to claims for damage to property, persons and the environment, nor can there be any assurance that the passage of more stringent laws or regulations in the future will not have a negative effect on our business, financial condition, or results of operations.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which oil and gas business operations are generally subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position, as well as a discussion of certain matters that specifically affect our operations.

Comprehensive Environmental Response, Compensation, and Liability Act. CERCLA, also known as the Superfund law, and comparable tribal and state laws may impose strict, joint and several liability, without regard to fault, on classes of persons who are considered to be responsible for the release of CERCLA hazardous substances into the environment. These persons include the owner or operator of the site where a release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Such claims may be filed under CERCLA, as well as state common law theories or tribal or state laws that are modeled after CERCLA. In the course of our operations, we generate waste that may fall within the definition of hazardous substances under CERCLA, as well as under the recently adopted Navajo Nation CERCLA which, unlike the federal CERCLA, defines hazardous substances to include oil and other hydrocarbons, thereby subjecting us to potential liability under CERCLA, tribal and state law counterparts to CERCLA and common law. Therefore, governmental agencies or third parties could seek to hold us responsible for all or part of the costs to clean up a site at which such hazardous substances may have been released or deposited, or other damages resulting from a release.

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Waste Handling. The Resource Conservation and Recovery Act (RCRA) and comparable tribal and state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and many of the other wastes associated with the exploration, development and production of oil or gas are currently exempt under federal law from regulation as RCRA hazardous wastes and instead are regulated as non-hazardous solid wastes. It is possible, however, that oil and gas exploration and production wastes now classified federally as non-hazardous could be classified as hazardous wastes in the future. In September 2010, the Natural Resources Defense Council filed a petition with the EPA, requesting it to reconsider the RCRA exemption for exploration, production and development wastes but, to date, the agency has not taken any action on the petition. Any such change could result in an increase in our operating expenses, which could have a material adverse effect on the results of operations and financial position. Also, in the course of operations, we generate some amounts of industrial wastes, such as paint wastes, waste solvents, and waste oils, that may be regulated as hazardous wastes under RCRA and tribal and state laws and regulations.

We have an interest in the Aneth Gas Processing Plant located in the Aneth Unit. This gas plant consists of a non-operational portion of the plant that has been substantially dismantled by Chevron, operational portion dedicated to compression. We are responsible for a portion of the costs of decommissioning and removal and clean-up of the non-operational portion of the plant and any restoration and other costs related to the operational processing facilities. For additional information concerning our obligations related to this plant, please read *Business and Properties Aneth Gas Processing Plant*.

Air Emissions. The federal Clean Air Act and comparable tribal and state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. These regulatory programs may require us to install and operate expensive emissions control equipment, modify our operational practices and obtain permits for existing operations and, before commencing construction on a new or modified source of air emissions, such laws may require us to reduce our emissions at existing facilities. As a result, we may be required to incur increased capital and operating costs. Federal, tribal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated tribal and state laws and regulations.

In June 2005, the EPA and ExxonMobil entered into a consent decree settling various alleged violations of the federal Clean Air Act associated with ExxonMobil s prior operation of the McElmo Creek Unit. In response, ExxonMobil submitted amended Title V and Prevention of Significant Deterioration (PSD) permit applications for the McElmo Creek Unit main flare and other sources, and also paid a civil penalty and costs associated with a Supplemental Environmental Project, or SEP. Pursuant to the consent decree, upgrades to the main flare were completed in May 2006 by ExxonMobil, and all of the remaining material compliance measures of the consent decree have been met by us. The EPA is processing the Title V and PSD permit applications required by consent decree. We remain subject to the consent decree, including stipulated penalties for violations of emissions limits and compliance measures set forth in the consent decree. We believe the consent decree may be terminated in 2013 by the EPA, although the EPA has given us no definite confirmation.

On July 1, 2011, EPA promulgated final rules titled Review of New Sources and Modifications in Indian Country. (Tribal Minor NSR Rules) 76 Fed. Reg. 38748-808 (July 1, 2011) (to be codified at 40 C.F.R. Parts 49 and 51). These rules became effective on August 30, 2011, and establish the phased implementation of a program of minor source permitting by EPA in Indian Country over a period of 36 months. Under the Tribal Minor NSR Rules, new wells and associated equipment located in Indian Country that will be minor sources even without emission controls need not obtain a permit prior to their construction for up to 36 months from the effective date of the rules (although they need to be registered with EPA in most instances), while such sources that exceed major source thresholds without legally and practically enforceable emission control requirements in effect must obtain a synthetic minor permit prior to their construction. The Tribal Minor NSR Rules specifically provide for a synthetic minor permit to be issued to an otherwise major source that takes permit restrictions, enforceable as a legal and practical matter, so that the source s potential to emit is less than the minimum amount set for major sources, i.e., 250 tons per year of criteria pollutants in so called attainment areas. We have begun to evaluate our existing and planned new sources in Indian Country for purposes of registering them, and eventually permitting them with EPA, and evaluating the need to apply for any synthetic minor permits for existing facilities that may undergo modifications. Delays in obtaining such new permits from EPA under the Tribal Minor NSR Rules could adversely affect our planned activities which previously were not subject to minor source permitting requirements or associated delays and expense. On August 16, 2012, the EPA published final rules that established new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s rule package included New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules also established specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. and more stringent leak detection requirements for natural gas processing plants. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, as well as court challenges to the rules, and EPA intends to issue revised rules in 2013 that are likely responsive to some of these requests. The final revised rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

Actual air emissions reported for these facilities are in material compliance with the terms and emission limits contained in the permit applications and the consent decree when emissions associated with qualified equipment malfunctions are taken into account.

Water Discharges. The federal Water Pollution Control Act, or the Clean Water Act, and analogous tribal and state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, including wetlands. The discharge of pollutants into regulated waters is prohibited by the Clean Water Act, except in accordance with the terms of a permit issued by the EPA or an authorized tribal or state agency. Federal, tribal and state regulatory agencies can impose administrative, civil and criminal penalties for unauthorized discharges or noncompliance with discharge permits or other requirements of the Clean Water Act and analogous tribal and state laws and regulations.

In addition, the Oil Pollution Act of 1990, or OPA, augments the Clean Water Act and imposes strict liability for owners and operators of facilities that are the source of a release of oil into waters of the United States. OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. For example, operators of oil and gas facilities must develop, implement, and maintain facility response plans, conduct annual spill training for employees and provide varying degrees of financial assurance to cover costs that could be incurred in responding to oil spills. In addition, owners and operators of oil and gas facilities may be subject to liability for cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills.

In November 2001, the EPA issued an administrative order to ExxonMobil for removal and remediation of oil and hydrocarbon contaminated ground water released as a result of a shallow casing leak at the McElmo Creek P-20 well that occurred in January 2001. In response, ExxonMobil performed various site assessment activities and began recovering oil from the ground water. We are obligated to complete the ground water monitoring and remedial activities required under the administrative order issued to ExxonMobil, at an estimated cost of approximately $100,000 per year, with anticipated closure to occur in 2013.

Underground Injection Control. Our underground injection operations are subject to the federal Safe Drinking Water Act, as well as analogous tribal and state laws and regulations. Under Part C of the Safe Drinking Water Act, the EPA established the Underground Injection Control program, which established the minimum program requirements for tribal and state programs regulating underground injection activities. The Underground Injection Control program includes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. Federal, tribal and state regulations require us to obtain a permit from applicable regulatory agencies to operate our underground injection wells. We believe we have obtained the necessary permits from these agencies for our underground injection wells and that we are in substantial compliance with permit conditions and applicable federal, tribal and state rules. Nevertheless, these regulatory agencies have the general authority to suspend or modify one or more of these permits if continued operation of one of the underground injection wells is likely to result in pollution of freshwater, the substantial violation of permit conditions or applicable rules, or leaks to the environment. Although we monitor the injection process of our wells, any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third parties for property damages and personal injuries.

Pipeline Integrity, Safety, and Maintenance. Our ownership interest in the McElmo Creek Pipeline has caused us to be subject to regulation by the federal Department of Transportation, or the DOT, under the Hazardous Liquid Pipeline Safety Act and comparable state statutes, which relate to the design, installation, testing, construction, operation, replacement and management of hazardous liquid pipeline facilities. Any entity that owns or operates such pipeline facilities must comply with such regulations, permit access to and copying of records, and file reports and provide required information. The DOT may assess fines and penalties for violations of these and other requirements imposed by its regulations. We believe we are in material compliance with all regulations imposed by the DOT pursuant to the Hazardous Liquid Pipeline Safety Act. Pursuant to the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, the DOT was required to issue new regulations by December 31, 2007, setting forth specific integrity management program requirements applicable to low stress hazardous liquid pipelines. We believe that these new regulations, which have yet to be issued, will not have a material adverse effect on our financial condition or results of operations.

Environmental Impact Assessments. Significant federal decisions, such as the issuance of federal permits or authorizations for many oil and gas exploration and production activities are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of Interior, to evaluate major federal agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment of the potential direct, indirect and cumulative impacts of a proposed project and/or, will prepare a more detailed Environmental Impact Statement that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans on federal lands, require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay any oil and gas development projects.

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Other Laws and Regulations

Climate Change. Recent scientific studies have suggested that emissions of gases commonly referred to as greenhouse gases or GHG, including CO_2, nitrogen dioxide and methane, may be contributing to warming of the Earth s atmosphere. Other nations have already agreed to regulate emissions of GHG pursuant to the United Nations Framework Convention on Climate Change, (UNFCCC) and the Kyoto Protocol, an international treaty (not including the United States) pursuant to which many UNFCCC member countries agreed to reduce their emissions of GHG to below 1990 levels by 2012. A successor treaty to the Kyoto Protocol has not been developed to date. In response to such studies and international action, the U.S. Congress has considered but not passed legislation to reduce emissions of GHG. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007, in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate GHG emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of GHG. The Court s holding in *Massachusetts v. EPA* that GHG fall under the federal Clean Air Act s definition of air pollutant has resulted in the regulation and permitting of GHG emissions from major stationary sources under the Clean Air Act, due to EPA s endangerment finding that links global warming to man-caused emissions of GHG, and the EPA s subsequent GHG Tailoring Rule, which subjects certain major sources of GHG emissions to Title V operating permit and New Source Review permitting requirements for the first time. The permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs will require affected facilities to meet emissions limits that are based on best available control technology, which will be established by the permitting agencies on a case-by-case basis. In July 2012, the Tailoring Rule became effective for all new facilities that emit at least 100,000 tons of GHG per year. Additionally, the EPA promulgated a mandatory GHG reporting rule that took effect January 1, 2010. This mandatory reporting rule (MRR) did not require reporting by Resolute for our operations in Aneth Field as initially promulgated. However, on March 23, 2010, EPA proposed several amendments to the MRR that would trigger reporting requirements for the Company. Among the amendments proposed are provisions that would apply to operators that inject CO_2 for enhanced oil recovery and geologic sequestration, regardless of the magnitude of associated CO_2 emissions, and also to operators of oil and gas systems that emit more than 25,000 metric tons of CO_2-equivalent GHG across an entire producing basin, based on the aggregated GHG emissions of all facilities in a basin under the common control of an operator. Furthermore, a number of states have taken legal measures to reduce emissions of GHG, primarily through the planned development of GHG emission inventories and/or regional cap and trade programs, but we do not currently conduct business in those states. The passage or adoption of additional legislation or regulations that restrict emissions of GHG or require reporting of such emissions in areas where we conduct business could adversely affect our operations.

Department of Homeland Security. The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security (DHS) to issue regulations establishing risk-based performance standards for the security at chemical and industrial facilities, including oil and gas facilities that are deemed to present high levels of security risk. The DHS is in the process of adopting regulations that will determine whether some of our facilities or operations will be subject to additional DHS-mandated security requirements. Under this authority, in April 2007, the DHS promulgated the Chemical Facilities Anti-Terrorism Standards (CFATS) regulations. Facilities that possessed any chemical on the CFATS Appendix A: DHS Chemicals of Interest List at or above the listed Screening Threshold Quantity for each chemical on the day Appendix A was published (November 20, 2007) are subject to CFATS regulation. We are currently not aware of any affected Company facilities subject to the CFATS regulations.

Occupational Safety and Health Act. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes that strictly govern protection of the health and safety of workers. The Occupational Safety and Health Administration s hazard communication standard and Process Safety Management (PSM) regulations, the Emergency Planning and Community Right-to-Know Act, and similar state statutes require that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, tribal, state and local government authorities, and the public. PSM requirements applicable to gas processing activities are an intended focus of OSHA enforcement in recent years, and emphasize the need for process safety information disclosure, including short and long-term off-site consequence analyses. We believe that we are in substantial compliance with applicable requirements of these and other OSHA and comparable tribal and state health and safety requirements.

Laws and Regulations Pertaining to Oil and Gas Operations on Navajo Nation Lands

General. Laws and regulations pertaining to oil and gas operations on Navajo Nation lands derive from both Navajo law and federal law, including federal statutes, regulations and court decisions, generally referred to as federal Indian law.

The Federal Trust Responsibility. The federal government has a general trust responsibility to Indian tribes regarding lands and resources that are held in trust for such tribes. The trust responsibility may be a consideration in courts resolution of disputes regarding Indian trust lands and development of oil and gas resources on Indian reservations. Courts may consider the compliance of the Secretary of the U.S. Department of the Interior, or the Interior Secretary, with trust duties in determining whether leases, rights-of-way or contracts relative to tribal land are valid and enforceable.

Tribal Sovereignty and Dependent Status. The U.S. Constitution vests in Congress the power to regulate the affairs of Indian tribes. Indian tribes hold a sovereign status that allows them to manage their internal affairs, subject to the ultimate legislative power of Congress. Tribes are therefore often described as domestic dependent nations, retaining all attributes of sovereignty that have not been taken away by Congress. Retained sovereignty includes the authority and power to enact laws and safeguard the health and welfare of the tribe and its members and the ability to regulate commerce on the reservation. In many instances, tribes have the inherent power to levy taxes and have been delegated authority by the United States to administer certain federal health, welfare and environmental programs.

Because of their sovereign status, Indian tribes also enjoy sovereign immunity from suit and may not be sued in their own courts or in any other court absent Congressional abrogation or a valid tribal waiver of such immunity. The United States Supreme Court has ruled that for an Indian tribe to waive its sovereign immunity from suit, such waiver must be clear, explicit and unambiguous.

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NNOGC is a federally chartered corporation incorporated under Section 17 of the Indian Reorganization Act and is wholly owned by the Navajo Nation. Section 17 corporations generally have broad powers to sue and be sued. Courts will review and construe the charter of a Section 17 corporation to determine whether the tribe has either universally waived the corporation s sovereign immunity, or has delegated that power to the Section 17 corporation.

The NNOGC federal charter of incorporation provides that NNOGC shares in the immunities of the Navajo Nation, but empowers NNOGC to waive such immunities in accordance with processes identified in the charter. NNOGC has contractually waived its sovereign immunity, and certain other immunities and rights it may have regarding disputes with us relating to certain of the Aneth Field Properties, in the manner specified in its charter. Although the NNOGC waivers are similar to waivers that courts have upheld, if challenged, only a court of competent jurisdiction may make that determination based on the facts and circumstances of a case in controversy.

Tribal sovereignty also means that in some cases a tribal court is the only court that has jurisdiction to adjudicate a dispute involving a tribe, tribal lands or resources or business conducted on tribal lands or with tribes. Although language similar to that used in our agreements with NNOGC that provide for alternative dispute resolution and federal or state court jurisdiction has been upheld in other cases, there is no guarantee that a court would enforce these dispute resolution provisions in a future case.

Federal Approvals of Certain Transactions Regarding Tribal Lands. Under current federal law, the Interior Secretary (or the Interior Secretary s appropriate designee) must approve any contract with an Indian tribe that encumbers, or could encumber, for a period of seven years or more, (1) lands owned in trust by the United States for the benefit of an Indian tribe or (2) tribal lands that are subject to a federal restriction against alienation, or collectively Tribal Lands. Failure to obtain such approval, when required, renders the contract void.

Except for our oil and gas leases, rights-of-way and operating agreements with the Navajo Nation, our agreements do not by their terms specifically encumber Tribal Lands, and we believe that no Interior Secretarial approval was required to enter into those agreements. With respect to our oil and gas leases and unit operating agreements, these and all assignments to us have been approved by the Interior Secretary. In the case of rights-of-way and assignments of these to us, some of these have been approved by the Interior Secretary and others are in various stages of applications for renewal and approval. It is common for these approvals to take an extended period of time, but such approvals are routine and we believe that all required approvals will be obtained in due course.

Federal Management and Oversight. Reflecting the federal trust relationship with tribes, the Bureau of Indian Affairs, or the BIA, exercises oversight of matters on the Navajo Nation reservation pertaining to health, welfare and trust assets of the Navajo Nation. Of relevance to us, the BIA must approve all leases, rights-of-way, applications for permits to drill, seismic permits, CO_2 pipeline permits and other permits and agreements relating to development of oil and gas resources held in trust for the Navajo Nation. While NNOGC has been successful in facilitating timely approvals from the BIA, such timeliness is not guaranteed and obtaining such approvals may cause delays in developing the Aneth Field Properties.

Resources Committee of the Navajo Nation Council. The Resources Committee is a standing committee of the Navajo Nation Tribal Council, and has oversight and regulatory authority over all lands and resources of the Navajo Nation. The Resources Committee reviews, negotiates and recommends to the Navajo Nation Tribal Council actions involving the approval of energy development agreements and mineral agreements; gives final approvals of rights of way, surface easements, geophysical permits, geological prospecting permits, and other surface rights for infrastructure; oversees and regulates all activities within the Navajo Nation involving natural resources and surface disturbance; sets policy for natural resource development and oversees the enforcement of federal and Navajo law in the development and utilization of resources, including issuing cease and desist orders and assessing fines for violation of its regulations and orders. The Resources Committee also has oversight authority over, among other agencies and matters, the Navajo Nation Environmental Protection Agency and Navajo Nation environmental laws, the Navajo Nation Minerals Department and Navajo Nation oil and gas laws and the Navajo Nation Land Department and Navajo Nation land use laws. While NNOGC has been successful thus far in facilitating timely approvals from the Resources Committee for our operations, such timeliness is not guaranteed and obtaining future approvals may cause delays in developing the Aneth Field Properties. Furthermore, the Navajo Nation Tribal Council was recently reorganized and reduced in size from 88 members to 24 members. While this change has not had any impact on our operations, we do not yet know the longer term implications, if any, this will have on the operation of the Tribal Council or the Resources Committee and their impact on our operations.

Navajo Nation Minerals Department of the Division of Natural Resources. The day-to-day operation of the Navajo Nation minerals program, including the initial negotiation of agreements, applications for approval of assignments, exercise of tribal preferential rights and most other permits and licenses relating to oil and gas development, is managed by the professional staff of the Navajo Nation Minerals Department, located within the Division of Natural Resources and subject to the oversight of the Resources Committee. The Resources Committee and the Navajo Nation Council typically defer to the Minerals Department in decisions to approve all leases and other agreements relating to oil and gas resources held in trust for the Navajo Nation. While NNOGC has been successful thus far in facilitating timely action and favorable recommendations from the Minerals Department for our operations, such timeliness is not guaranteed and obtaining future approvals may cause delays in developing the Aneth Field Properties.

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Taxation Within the Navajo Nation. In certain instances, federal, state and tribal taxes may be applicable to the same event or transaction, such as severance taxes. State taxes are rarely applicable within the Navajo Nation Reservation except as authorized by Congress or when the application of such taxes does not adversely affect the interests of the Navajo Nation. Federal taxes of general application are applicable within the Navajo Nation, unless specifically exempted by federal law. We currently pay the following taxes to the Navajo Nation:

Oil and Gas Severance Tax. We pay severance tax to the Navajo Nation. The severance tax is payable monthly and is 4% of our gross proceeds from the sale of oil and gas. Approximately 84% of the Aneth Unit is subject to the Navajo Nation severance tax. The other 16% of the Aneth Unit is exempt because it is either located off of the reservation or it is incremental enhanced oil recovery production, which is not subject to the severance tax. Presently all of the McElmo Creek and Ratherford Units are subject to the severance tax.

Possessory Interest Tax. We pay a possessory interest tax to the Navajo Nation. The possessory interest tax applies to all property rights under a lease within the Navajo Nation boundaries, including natural resources.

Sales Tax. We pay the Navajo Nation a 4% sales tax in lieu of the Navajo Business Activity Tax. All goods and services purchased for use on the Navajo Nation reservation are subject to the sales tax. The sale of oil and gas is exempt from the sales tax.

Royalties from Production on Navajo Nation Lands. Under our agreements and leases with the Navajo Nation, we pay royalties to the Navajo Nation. The Navajo Nation is entitled to take its royalties in kind, which it currently does for its oil royalties. The Minerals Management Service of the United States Department of the Interior has the responsibility for managing and overseeing royalty payments to the Navajo Nation as well as the right to audit royalty payments.

Navajo Preference in Employment Act. The Navajo Nation has enacted the Navajo Preference in Employment Act, or the Employment Act, requiring preferential hiring of Navajos by non-governmental employers operating within the boundaries of the Navajo Nation. The Employment Act requires that any Navajo candidate meeting job description requirements receives a preference in hiring. The Employment Act also provides that Navajo employees can only be terminated, penalized, or disciplined for just cause, requires a written affirmative action plan that must be filed with the Navajo Nation, establishes the Navajo Labor Commission as a forum to resolve employment disputes and provides authority for the Navajo Labor Commission to establish wage rates on construction projects. The restrictions imposed by the Employment Act and its recent broad interpretations by the Navajo Supreme Court may limit our pool of qualified candidates for employment.

Navajo Business Opportunity Act. Navajo Nation law requires companies doing business in the Navajo Nation to provide preference priorities to certified Navajo-owned businesses by giving them a first opportunity and contracting preference for all contracts within the Navajo Nation. While this law does not apply to the granting of mineral leases, subleases, permits, licenses and transactions governed by other applicable Navajo and federal law, we treat this law as applicable to our material non-mineral contracts and procurement relating to our general business activities within the Navajo Nation.

Navajo Environmental Laws. The Navajo Nation has enacted various environmental laws that may be applicable to our Aneth Field Properties. As a practical matter, these laws are patterned after similar federal laws, and the EPA currently enforces these laws in conjunction with the Navajo EPA. The current practice does not preclude the Navajo Nation from taking a more active role in enforcement or from changing direction in the future. Some of the Navajo Nation environmental laws not only provide for civil, criminal and administrative penalties, but also provide for third-party suits brought by Navajo Nation tribal members directly against an alleged violator, with specified jurisdiction in the Navajo Nation District Court in Window Rock. An example of this relates to the March 2008 adoption by the Navajo Nation of the Navajo Comprehensive Environmental Response, Compensation, and Liability Act (Navajo CERCLA), which gives the Navajo EPA broad authority over environmental assessment and remediation of facilities contaminated with hazardous substances. Navajo CERCLA is patterned after federal CERCLA with the important exception that, unlike federal CERCLA, Navajo CERCLA considers oil and other hydrocarbons to be hazardous substances subject to CERCLA response actions and damages. Navajo CERCLA also imposes a tariff on the transportation of hazardous substances, including petroleum and petroleum products, across Navajo lands. Since 2008, we have been negotiating with representatives of the Navajo Nation Council, Navajo Department of Justice, Navajo Environmental Protection Agency, NNOGC, an industry group headed by the New Mexico Oil and Gas Association and Colorado Oil and Gas Association, (the NMOGA Group), and others, to mitigate Navajo CERCLA s potential impact on oilfield operations on Navajo lands. The NMOGA Group challenged the validity of the law and entered into a tolling agreement with Navajo EPA (which was subsequently amended several times) that forestalled material implementation of Navajo CERCLA at oil and gas facilities while appropriate rules and guidelines are developed with input from the oil and gas sector. A partial settlement agreement was entered into in January, 2012 among the NMOGA Group parties and the Navajo Nation. Under the terms of this agreement, enforcement of most of the material provisions of Navajo CERCLA is delayed for at least five years and the NMOGA Group retains its ability to file suit to challenge the law at such five-year period. In the interim, Navajo Nation EPA has indicated it will require routine reporting of spills of oil and other hazardous substances to now go directly to the Navajo CERCLA program personnel within Navajo Nation EPA, in addition to that information going to other spill reporting contacts within Navajo Nation EPA.

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Thirty-Two Point Agreement. An explosion at an ExxonMobil facility in Aneth Field in December 1997 prompted protests by local tribal members and temporary shutdown of the field. The protesters asserted concerns about environmental degradation, health problems, employment opportunities and renegotiating leases. The protest was settled among the local residents, ExxonMobil and the Navajo Nation by the Thirty-Two Point Agreement that provided, among other things, for ExxonMobil to pay partial salaries for two Navajo public liaison specialists, follow Navajo hiring practices, and settle further issues addressed in the Thirty-Two Point Agreement in the Navajo Nation s peacemaker courts, which follow a community-level conflict resolution format. After the Thirty-Two Point Agreement was executed, Aneth Field resumed normal operations. While we did not formally assume the obligations of ExxonMobil under the Thirty-Two Point Agreement when we acquired the ExxonMobil Properties in 2006, it has been our policy to voluntarily comply with this agreement. While we believe that our relations with the Navajo Nation are satisfactory, it is possible that employee relations or community relations degrade to a point where protests and shutdown occur in the future.

Moratorium on Future Oil and Gas Development Agreements and Exploration. In February 1994, the Navajo Nation issued a moratorium on future oil and gas development agreements and exploration on lands situated within the Aneth Chapter on the Navajo Reservation. All of the Aneth Unit and a significant portion of the McElmo Creek Unit are located within the Aneth Chapter. The Navajo Nation has recently taken the position that the term of the moratorium is indefinite. Given that our operations within the Aneth Chapter are based on existing agreements and that we currently do not contemplate new exploration in this mature field, the moratorium has had and is expected to continue to have minor impact to our operations.

Other Regulation of the Oil and Gas Industry

The oil and gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state and Native American tribes, are authorized by statute to issue rules and regulations binding on the oil and gas industry and individual companies, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production. Our operations are subject to various types of regulation at federal, state, local and Navajo Nation levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities, the Navajo Nation and other Native American tribes also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or allowables ;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third-parties.

On state, federal and Indian lands, the Bureau of Land Management laws and regulations oversee the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third-parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit or limit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas that we can produce from our wells or limit the number of wells or the locations where we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and gas within its jurisdiction.

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Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of gas and the manner in which our production is marketed. Federal Energy Regulatory Commission (FERC) has jurisdiction over the transportation and sale for resale of gas in interstate commerce by gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic gas sold in first sales, which include all of our sales of our own production.

FERC also regulates interstate gas transportation rates and service conditions, which affects the marketing of gas that we produce, as well as the revenue we receive for sales of our gas. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC s initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach, recently pursued by FERC and Congress, will continue indefinitely into the future nor can it determine what effect, if any, future regulatory changes might have on gas related activities.

Under FERC s current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states on-shore and in-state waters. Although its policy is still in flux, FERC recently has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

Hydraulic Fracturing Disclosure and Possible Regulation or Prohibition. Hydraulic fracturing or fracing is a process used by oil and gas producers in the completion or re-working of some oil and gas wells. Water, sand and certain chemical additives are injected under high pressure into subsurface formations to create and prop open fractures and thus enable fluids that would otherwise remain trapped in the formation to flow to the surface. Fracing has been in use for many years in a variety of geologic formations. Combined with advances in drilling technology, recent advances in fracing technology have contributed to a large increase in production of gas and oil from shales that would otherwise not be economically productive. Fracing is typically subject to state oil and gas agencies regulatory oversight, and has not been regulated at the federal level. However, due to assertions that fracing may adversely affect drinking water supplies, the federal EPA has commenced a study of the potentially adverse impacts that fracing may have on water quality and public health, and a committee of the U.S. House of Representatives has commenced its own investigation into fracing practices. Additionally, legislation has been introduced in Congress to amend the federal Safe Drinking Water Act (SDWA) to subject fracing to federal regulation under the SDWA, and to require the disclosure of chemical additives used in fracing fluids. If enacted, such legislation could require fracing to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping requirements, and meet plugging and abandonment requirements, in addition to those already applicable to well site reclamation under various federal, tribal and state laws. We routinely utilize hydraulic fracturing techniques in many of our reservoirs. Adoption of legislation and implementing regulations placing restrictions on fracing could impose operational delays, increased operating costs and additional regulatory burdens on our exploration and production activities, which could make it more difficult to perform hydraulic fracturing, resulting in reduced amounts of oil and gas being produced, as well as increased costs of compliance and doing business. We disclose information pertaining to frac fluids, additives, and chemicals to the FracFocus databases in compliance with statewide requirements established by the Texas Railroad Commission and Wyoming Oil and Gas Conservation Commission. We are currently waiting to see what requirements will be promulgated by the Navajo Nation before disclosing similar information for wells fractured on Navajo lands.

Employees

As of December 31, 2012, we had 227 full-time employees, of which 55 were field level employees represented by the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, or USW labor union, and are covered by a collective bargaining agreement. We believe that we have a satisfactory relationship with our employees.

Offices

We currently lease approximately 40,000 square feet of office space in Denver, Colorado at 1675 Broadway, Suite 1950, Denver, Colorado 80202, where our principal offices are located. In addition, we own and maintain field offices in Colorado, Utah, Wyoming and Texas and leases other, less significant, office space in locations where staff are located. We believe that our office facilities are adequate for our current needs and that additional office space can be obtained if necessary.

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Available Information

We maintain a link to investor relations information on our website, *www.resoluteenergy.com*, where we make available, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We also make available on our website copies of the charters of the audit, compensation and corporate governance/nominating committees of our Board of Directors, our code of business conduct and ethics, audit committee whistleblower policy, stockholder and interested parties communication policy and corporate governance guidelines. Stockholders may request a printed copy of these governance materials or any exhibit to this report by writing to the Secretary, Resolute Energy Corporation, 1675 Broadway, Suite 1950, Denver, Colorado 80202. You may also read and copy any materials we file with the SEC at the SEC s Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website at *www.sec.gov* that contains the documents we file with the SEC. Our website and the information contained on or connected to our website is not incorporated by reference herein and our web address is included as an inactive textual reference only.

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ITEM 1A. RISK FACTORS

You should consider carefully the following risk factors, as well as the other information set forth in this Form 10-K.

Risks Related to Our Business, Operations and Industry

The risk factors set forth below are not the only risks that may affect our business. Our business could also be affected by additional risks not currently known or that we currently deem to be immaterial. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Our oil production from the Aneth Field Properties is presently connected by pipeline to only one customer, and such sales are dependent on gathering systems and transportation facilities that we do not control. With only one pipeline-connected customer, when these facilities or systems are unavailable, our operations can be interrupted and our revenue reduced.

The marketability of our oil and gas production depends in part upon the availability, proximity and capacity of pipelines, gas gathering systems, and processing facilities owned by third parties. In general, we do not control these facilities and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely affect our ability to deliver to market the oil and gas we produce, and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our oil and gas is dependent upon coordination among third parties who own pipelines, transportation and processing facilities that we use, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt our operations. These are risks for which we generally do not maintain insurance.

With respect to oil produced at our Aneth Field Properties, we operate in a remote part of southeastern Utah, and currently sell all of our oil production to a single customer, Western. The purchase agreement with Western, effective August 2011, provides for a fixed differential to the NYMEX price for crude oil of $6.25 per Bbl, with future adjustments to reflect any increase in transportation costs from the field to the refinery. The agreement covers up to 8,000 combined barrels per day of our and NNOGC Base Volume and an Additional Volume of up to 3,000 barrels per day. The agreement contains a two year term for the Base Volume and a six month term for the Additional Volume, each commencing on August 1, 2011. Both continue automatically on a month-to-month basis after expiration of the initial term unless terminated by either party with 180 day prior written notice (120 days for the Additional Volume). The agreement may also be terminated by Western upon sixty days notice, if Western s right-of-way agreements with the Navajo Nation are declared invalid and either Western is prevented from using such rights-of-way or the Navajo Nation declares Western to be in trespass with respect to such rights-of-way.

Western refines our oil at their 26,000 barrel per day Gallup refinery in Gallup, New Mexico. Our production is transported to the refinery via the Running Horse oil pipeline owned by NNOGC to the Bisti terminal, approximately 20 miles south of Farmington, New Mexico, that serves the refinery. Our oil has been jointly marketed to Western with NNOGC. The combined volumes were approximately 9,100 barrels of oil per day as of year-end. See *Business and Properties Marketing and Customers Aneth Field.* There are presently no pipelines in service that run the entire distance from the Aneth Field Properties to any alternative markets. If Western did not purchase our oil, we would have to transport it to other markets by a combination of the NNOGC pipeline, truck and rail, which would result, in the short term, in a lower price relative to the NYMEX price than we currently receive. In the future we may receive prices with a greater differential to NYMEX than we currently receive, which if not offset by increases in the NYMEX price for oil, could result in a material adverse effect on our financial results.

We would also have to find alternative markets if Western s refining capacity in the region is temporarily or permanently shut down for any reason or if NNOGC s pipeline to Western s refineries is temporarily or permanently shut-in for any reason. We do not have any control over Western s decisions with respect to its refineries. We would also not have control over similar decisions by any replacement customers.

We customarily ship oil to Western daily and receive payment on the twentieth day of the month following the month of production. As a result, at any given time, Western owes us between 20 and 50 days of production revenue. Based upon average production from Aneth Field during the quarter ended December 31, 2012, and a NYMEX oil price of $90 per Bbl, Western could owe us between $10.8 million and $26.9 million. If Western defaults on its obligation to pay us for the oil we have delivered, our income would be materially and negatively affected. Both Moody s Investor Services and Standard & Poor s have assigned credit ratings to Western s long-term debt that are below investment grade.

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Oil and gas prices are volatile and change for reasons that are beyond our control. Decreases in the price we receive for our oil and gas production can adversely affect our business, financial condition, results of operations and liquidity and impede our growth.

The oil and gas markets are highly volatile, and we cannot predict future prices. Our revenue, profitability and cash flow depend upon the prices and demand for oil, gas and NGL. The markets for these commodities are very volatile and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Prices for oil, gas and NGL may fluctuate widely in response to relatively minor changes in the supply of and demand for the commodities, market uncertainty and a variety of additional factors that are beyond our control, such as:

- domestic and foreign supply of and demand for oil and gas, including as a result of technological advances affecting energy consumption and supply;
- weather conditions;
- overall domestic and global political and economic conditions;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- the price of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- technological advances affecting energy consumption;
- variations between product prices at sales points and applicable index prices;
- domestic, tribal and foreign governmental regulations and taxation;
- the effect of energy conservation efforts;
- the capacity, cost and availability of oil and gas pipelines and other transportation and gathering facilities, and the proximity of these facilities to our wells;
- the availability of refining and processing capability;
- factors specific to the local and regional markets where our production occurs; and

the price and availability of alternative fuels.

In the past, the price of oil has been extremely volatile, and we expect this volatility to continue. For example, during the twelve months ended December 31, 2012, the NYMEX price for light sweet crude oil ranged from a high of $109.49 per Bbl to a low of $77.69 per Bbl. For calendar year 2011, the range was from a high of $113.93 per Bbl to a low of $75.67 per Bbl, and for the five years ended December 31, 2012, the price ranged from a high of $145.29 per Bbl to a low of $31.41 per Bbl.

A decline in oil and gas prices can significantly affect many aspects of our business, including financial condition, revenue, results of operations, liquidity, rate of growth and the carrying value of our oil and gas properties, all of which depend primarily or in part upon those prices. For example, declines in the prices we receive for our oil and gas adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. In addition, declines in prices reduce the amount of oil and gas that we can produce economically and, as a result, adversely affect our quantities of proved reserves. Among other things, a reduction in our reserves can limit the capital available to us, as the maximum amount of available borrowing under our revolving credit facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantities of those reserves.

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Developing and producing oil and gas are costly and high-risk activities with many uncertainties that could adversely affect our financial condition or results of operations, and insurance may not be available or may not fully cover losses.

There are numerous risks associated with developing, completing and operating a well, and cost factors can adversely affect the economics of a well. Our development and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of rigs, equipment, labor or other services;
- unexpected operational events and/or conditions;
- reductions in oil or gas prices or increases in the differential between index oil or gas prices and prices received;
- increases in severance taxes;
- limitations on our ability to sell our oil or gas production;
- adverse weather conditions and natural disasters;
- facility or equipment malfunctions, and equipment failures or accidents;
- pipe or cement failures and casing collapses;
- compliance with environmental and other governmental requirements;
- environmental hazards, such as leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- lost or damaged oilfield development and service tools;
- unusual or unexpected geological formations, and pressure or irregularities in formations;
- fires, blowouts, surface craterings and explosions;
- shortages or delivery delays of supplies, equipment and services;
- title problems;

- objections from surface owners and nearby surface owners in the areas where we operate; and

- uncontrollable flows of oil, gas or well fluids.

Any of these or other similar occurrences could reduce our cash from operations or result in the disruption of our operations, substantial repair costs, significant damage to property, environmental pollution and impairment of our operations. The occurrence of these events could also affect third parties, including persons living near our operations, our employees and employees of our contractors, leading to injuries or death.

Insurance against all operational risk is not available to us, and pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We do not maintain business interruption insurance and also may not maintain insurance on all of our equipment. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Changes in the insurance markets subsequent to the terrorist attacks on September 11, 2001 have made it more difficult for us to obtain coverage for terrorist attacks and related risks. We may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and any insurance coverage we do obtain may contain large deductibles or it may not cover all hazards or potential losses. Losses and liabilities from uninsured and underinsured events or a delay in the payment of insurance proceeds could adversely affect our business, financial condition and results of operations.

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A significant part of our development plan involves the implementation of our CO_2 projects. The supply of CO_2 and efficacy of the planned projects is uncertain, and other resources may not be available or may be more expensive than expected, which could adversely impact production, revenue and earnings, and may require a write-down of reserves.

Producing oil and gas reservoirs are depleting assets generally characterized by declining production rates that vary depending upon factors such as reservoir characteristics. A significant part of our business strategy depends on our ability to successfully implement CO_2 floods and other development projects we have planned for the Aneth Field Properties in order to counter the natural decline in production from the field. As of December 31, 2012, approximately 57% of our estimated net proved reserves were classified as proved developed non-producing and proved undeveloped, meaning we must undertake additional development activities before we can produce those reserves. These development activities involve numerous risks, including insufficient quantities of CO_2, project execution risks and cost overruns, insufficient capital to allocate to these projects, and inability to obtain equipment, manpower and materials that are necessary to successfully implement these projects.

A critical part of our development strategy depends upon our ability to purchase CO_2. We are party to a contract to purchase CO_2 from Kinder Morgan. All of the CO_2 we have under contract comes from McElmo Dome Field. If we are unable to purchase sufficient CO_2 under this contract, either because Kinder Morgan is unable or is unwilling to supply the contracted volumes, we would have to purchase CO_2 from other owners of CO_2 in McElmo Dome Field or elsewhere. In such an event, we may not be able to locate substitute supplies of CO_2 at acceptable prices or at all. In addition, certain suppliers of CO_2, such as Kinder Morgan, use CO_2 in their own tertiary recovery projects. As a result, if we need to purchase additional volumes of CO_2, these suppliers may not be willing to sell a portion of their supply of CO_2 to us if their own demand for CO_2 exceeds their supply. Additionally, even if adequate supplies are available for delivery from the McElmo Dome Field, we could experience temporary or permanent shut-ins of our pipeline that delivers CO_2 from that field to the Aneth Field Properties. If we are unable to obtain the CO_2 we require and are unable to undertake our development projects or if our development projects are significantly delayed, our recoverable reserves may be less than we currently anticipate, we will not realize our expected incremental production, and our expected decline in the rate of production from the Aneth Field Properties will be accelerated. If our requirements for CO_2 were to decrease, we could be required to incur costs for CO_2 that we have not purchased or to purchase more CO_2 than we could use effectively. For more information about our CO_2 development program and minimum financial obligations under the Kinder Morgan contract, please read *Business and Properties Description of Properties Aneth Field Properties*.

In addition, our estimate of future development costs, including with respect to our planned CO_2 development projects, is based on our current expectation of prices and other costs of CO_2, equipment and personnel we will need in the future to implement such projects. Our actual future development costs may be significantly higher than we currently estimate, and delays in executing our development projects could result in higher labor and other costs associated with these projects. If costs become too high, our future development projects may not provide economic results and we may be forced to abandon our development projects.

Furthermore, the results we obtain from our CO_2 flood projects may not be the same as we expected when preparing our estimate of net proved reserves. Lower than expected production results or delays in when we first realize additional production as a result of our CO_2 flood projects will reduce the value of our reserves, which could reduce our ability to incur indebtedness, require us to use cash to repay indebtedness or to satisfy our derivative obligations, and require us to write-down the value of our reserves. Therefore, our future reserves, production and future cash flow are highly dependent on our success in efficiently developing and exploiting our current estimated net proved undeveloped reserves.

Currently, the majority of our oil producing properties are located on the Navajo Reservation, making us vulnerable to risks associated with laws and regulations pertaining to the operation of oil and gas properties on Native American tribal lands.

Substantially all of our Aneth Field Properties, which represent approximately 75% of our 2012 oil and gas revenues and total proved reserves at December 31, 2012, are located on the Navajo Reservation in southeastern Utah. Operation of oil and gas interests on Indian lands presents unique considerations and complexities. These arise from the fact that Indian tribes are dependent sovereign nations located within states, but are subject only to tribal laws and treaties with, and the laws and Constitution of, the United States. This creates a potential overlay of three jurisdictional regimes Indian, federal and state. These considerations and complexities could affect various aspects of our operations, including real property considerations, employment practices, environmental matters and taxes.

For example, we are subject to the Navajo Preference in Employment Act. This law requires that we give preference in hiring to members of the Navajo Nation, or in some cases other Native American tribes, if such a person is qualified for the position, rather than hiring the most qualified person. A further regulatory requirement is imposed by the Navajo Nation Business Opportunity Act which requires us to give preference to Navajo owned businesses when we are hiring contractors. These regulatory restrictions can negatively affect our ability to recruit and retain the most highly qualified personnel or to utilize the most experienced and economical contractors for our projects.

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Furthermore, because tribal property is considered to be held in trust by the federal government, before we can take actions such as drilling, pipeline installation or similar actions, we are required to obtain approvals from various federal agencies that are in addition to customary regulatory approvals required of oil and gas producers operating on non-Indian property. We are also required to obtain approvals from the Resources Committee, which is a standing committee of the Navajo Nation Tribal Council, before we can take similar actions with respect to the Aneth Field Properties. These approvals could result in delays in our implementation of, or otherwise prevent us from implementing our development program. These approvals, even if ultimately obtained, could result in delays in our ability to implement our development program.

In addition, under the Native American laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages.

Thirty-Two Point Agreement. An explosion at an ExxonMobil facility in Aneth Field in December 1997 prompted protests by local tribal members and temporary shutdown of the field. The protesters asserted concerns about environmental degradation, health problems, employment opportunities and renegotiating leases. The protest was settled among the local residents, ExxonMobil and the Navajo Nation by the Thirty-Two Point Agreement that provided, among other things, for ExxonMobil to pay partial salaries for two Navajo public liaison specialists, follow Navajo hiring practices, and settle further issues addressed in the Thirty-Two Point Agreement in the Navajo Nation s peacemaker courts, which follow a community-level conflict resolution format. After the Thirty-Two Point Agreement was executed, Aneth Field resumed normal operations. While we did not formally assume the obligations of ExxonMobil under the Thirty-Two Point Agreement when we acquired the ExxonMobil Properties in 2006, it has been our policy to voluntarily comply with this agreement. While we believe that our relations with the Navajo Nation are satisfactory, it is possible that employee relations or community relations degrade to a point where protests and shutdown occur in the future.

For additional information about the legal complexities and considerations associated with operating on the Navajo Reservation, please read *Business and Properties Laws and Regulations Pertaining to Oil and Gas Operations on Navajo Nation Lands*.

The statutory preferential purchase right held by the Navajo Nation to acquire transferred Navajo Nation oil and gas leases and NNOGC s right of first negotiation could diminish the value we may be able to receive in a sale of our properties.

Nearly all of our Aneth Field Properties are located on the Navajo Reservation. The Navajo Nation has a statutory preferential right to purchase at the offered price any Navajo Nation oil and gas lease or working interest in such a lease at the time a proposal is made to transfer the lease or interest. The existence of this right can make it more difficult to sell a Navajo Nation oil and gas lease because this right may discourage third parties from purchasing such a lease and, therefore, could reduce the value of our leases if we were to attempt to sell them. In addition, under the terms of our Cooperative Agreement with NNOGC, we are obligated to first negotiate with NNOGC to sell our Aneth Field Properties before we may offer to sell such properties to any other third party. This contractual right could make it more difficult for us to sell our Aneth Field Properties. For additional information about the right of first negotiation for the benefit of NNOGC, please read *Business and Properties Relationship with the Navajo Nation*.

NNOGC has an option to purchase an additional interest in our Aneth Field Properties.

In addition to the options exercised by NNOGC in April 2012 to purchase 10% of our interests in Aneth Field for $100 million, NNOGC also has an option to purchase up to an additional 10% of our interest in the Aneth Field Properties (as it stood prior to the 2012 option exercise and excluding the interest acquired from Denbury and other minority interests). This option is exercisable for cash as of July 2017 at the then fair market value of the interests. If NNOGC exercises its purchase option in full, it could acquire from us undivided working interests representing a 6.05% working interest in the Aneth Unit, a 7.5% working interest in the McElmo Creek Unit and a 5.9% working interest in the Ratherford Unit. If NNOGC were to exercise this option, we might not be able to effectively redeploy the cash we receive.

Any acquisitions we complete are subject to substantial risks that could negatively affect our financial condition and results of operations.

Even if we do make acquisitions that we believe will enhance our growth, financial condition or results of operations, any acquisition involves potential risks, such as the Permian Acquisitions, including, among other things:

- the validity of our assumptions about the acquired properties or company s reserves, future production, the future prices of oil and gas, infrastructure requirements, environmental and other liabilities, revenue and costs;

an inability to integrate successfully the properties and businesses we acquire;

a decrease in our liquidity to the extent we use a significant portion of our available cash or borrowing capacity to finance acquisitions or operations of the acquired properties;

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- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions or operations of the acquired properties;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management s attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property or business will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

Also, our review of acquired properties is inherently incomplete because it is generally not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential problems. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. The potential risks in making acquisitions could adversely affect our ability to achieve anticipated levels of cash flows from the acquired businesses or realize other anticipated benefits of those acquisitions.

U.S. and global economic recession could have a material adverse effect on our business and operations.

Any or all of the following may occur if the recent crisis in the domestic and global financial and securities markets returns or economic conditions worsen:

- We may be unable to obtain additional debt or equity financing, which would require us to limit our capital expenditures and other spending. This would lead to lower growth in our production and reserves than if we were able to spend more than our cash flow. Financing costs may significantly increase as lenders may be reluctant to lend without receiving higher fees and spreads.
- The economic slowdown has led and could continue to lead to lower demand for crue oil and natural gas by individuals and industries, which in turn has resulted and could continue to result in lower prices for the oil and gas sold by us, lower revenues and possibly losses.
- The lenders under our revolving credit facility may become more restrictive in their lending practices or unable or unwilling to fund their commitments, which would limit our access to capital to fund our capital expenditures and operations. This would limit our ability to generate revenues as well as limit our projected production and reserves growth, leading to declining production and possibly losses.
- The losses incurred by financial institutions as well as the bankruptcy of some financial institutions heightens the risk that a counterparty to our derivative instruments could default on its obligations. These losses and the possibility of a counterparty declaring bankruptcy may affect the ability of the counterparties to meet their obligations to us on derivative transactions, which

could reduce our revenues from derivatives at a time when we are also receiving a lower price for our gas and oil sales. As a result, our financial condition could be materially adversely affected.

Our credit facility bears floating interest rates based on the London Interbank Offered Rate, or LIBOR. As banks were reluctant to lend to each other to avoid risk, LIBOR increased to unprecedented spread levels in 2008. This causes higher interest expense for unhedged levels of LIBOR-based borrowings.

Our credit facility requires the lenders to redetermine our borrowing base semi-annually. The redeterminations are based on our proved reserves using price assumptions determined by each lender, with effect given to our derivative positions. It is possible that the lenders could reduce their price assumptions used to determine reserves for calculating our borrowing base and our borrowing base could be reduced. This would reduce our funds available to borrow.

Bankruptcies of purchasers of our oil and gas could lead to the delay or failure of us to receive the revenues from those sales.

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Our planned operations, as well as replacement of our production and reserves, will require additional capital that may not be available.

Our business is capital intensive, and requires substantial expenditures to maintain currently producing wells, to make the acquisitions of additional reserves and/or conduct the exploration, exploitation and development program necessary to replace our reserves, to pay expenses and to satisfy our other obligations. These activities will require cash flow from operations, additional borrowings or proceeds from the issuance of additional equity, or some combination thereof, which may not be available to us.

For example, we expect to spend an additional $751.2 million of capital expenditures (including CO_2 purchases) over the next 33 years to implement and complete our proved developed non-producing and proved undeveloped projects. We expect to incur approximately $467.0 million of these future capital expenditures between 2013 and 2017 based on the capital plan contemplated by our December 2012 SEC reserve report. To the extent our production and reserves decline faster than we anticipate, we will require a greater amount of capital to maintain our production. Our ability to obtain bank financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering, the covenants in our revolving credit facility, and the Senior Notes or future debt agreements, adverse market conditions or other contingencies and uncertainties that are beyond our control. Our failure to obtain the funds necessary for future activities could materially affect our business, results of operations and financial condition. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our activities and our ability to pay dividends. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional equity may result in significant equity holder dilution.

Inadequate liquidity could materially and adversely affect our business operations in the future.

Our ability to generate cash flow depends upon numerous factors related to our business that may be beyond our control, including:

- the amount of oil and gas we produce;
- the price at which we sell our oil and gas production and the costs we incur to market our production;
- the effectiveness of our commodity price hedging strategy;
- the development of proved undeveloped properties and the success of our enhanced oil recovery activities;
- the level of our operating and general and administrative costs;
- our ability to replace produced reserves;
- prevailing economic conditions;
- government regulation and taxation;
- the level of our capital expenditures required to implement our development projects and make acquisitions of additional reserves;
- our ability to borrow under our revolving credit facility or future debt agreements;

debt service requirements contained in our revolving credit facility and Senior Notes or future debt agreements;

fluctuations in our working capital needs; and

timing and collectability of receivables.

Failure to maintain adequate liquidity could result in an inability to replace reserves and production, to maintain ownership of undeveloped leasehold and adverse borrowing base determinations. Any or all of the foregoing could materially and adversely affect our business and results of operations.

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If we do not make acquisitions of reserves on economically acceptable terms, our future growth and ability to maintain production will be limited to only the growth we may achieve through the development of our proved developed non-producing and proved undeveloped reserves and exploration of our non-proved leaseholds.

Producing oil and gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline we have projected for our existing wells may be different than the decline rate actually realized. Our future oil and gas reserves and production and, therefore, our cash flow and income are highly dependent upon our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

We intend to grow by bringing our proved developed non-producing reserves into production, developing our proved undeveloped reserves and exploring for and finding additional reserves on our unproved properties. Our ability to further grow depends in part on our ability to make acquisitions, particularly in the event NNOGC exercises their options to increase their working interest in the Aneth Field Properties. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with the seller;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to acquire properties containing proved reserves at acceptable costs, our total level of proved reserves and associated future production will decline as a result of the ongoing production of our reserves.

Exploration and development drilling may not result in commercially productive reserves.

We may not encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling whether we will find oil or gas or, if found, that the hydrocarbons will be produced economically. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment;
- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions; and

compliance with environmental and other governmental requirements.

Shortages of qualified personnel or field supplies, equipment and services could affect our ability to execute our plans on a timely basis, reduce our cash flow and adversely affect our results of operations.

The demand for qualified and experienced geologists, geophysicists, engineers, field operations specialists, landmen, financial experts and other personnel in the oil and gas industry can fluctuate significantly, often in correlation with oil and gas prices, causing periodic shortages. From time to time, there have also been shortages of drilling rigs and other field supplies, equipment and services, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors can also result in significant increases in costs for equipment, services, supplies and personnel. Higher oil and gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Historically, increased demand resulting from high commodity prices have at times significantly increased costs and resulted in some difficulty in obtaining drilling rigs, experienced crews and related services. We may continue to experience such difficulties in the future. If shortages persist or prices continue to increase, our profit margin, cash flow and operating results could be adversely affected and our ability to conduct our operations in accordance with current plans and budgets could be restricted.

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We are a party to a contract that requires us to pay for a minimum quantity of CO_2. This contract limits our ability to curtail costs if our requirements for CO_2 decrease.

Our contract with Kinder Morgan requires us to take, or pay for if not taken, a minimum volume of CO_2 monthly. The take-or-pay obligations result in minimum financial obligations during the contract term. The take-or-pay provisions in this contract allow us to subsequently apply take-or-pay payments made to volumes subsequently taken, but these provisions have limitations and we may not be able to utilize all such amounts paid if the limitations apply or if we do not subsequently take sufficient volumes to utilize the amounts previously paid.

We are subject to complex federal, state, tribal, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Exploration, exploitation, development, production and marketing operations in the oil and gas industry are regulated extensively at the federal, state and local levels. In addition, substantially all of our current leases in Aneth Field are regulated by the Navajo Nation. Some of our future leases may be regulated by Native American tribes. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and properly abandon oil and gas wells and other recovery operations. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our operations or denial or revocation of permits and subject us to administrative, civil and criminal penalties.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact statements and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation by oil and gas producing states and the Navajo Nation regarding conservation practices, protection of correlative rights and other concerns. These regulations affect our operations and could limit the quantity of oil and gas we may produce and sell. A risk inherent in our CO_2 flood project is the need to obtain permits from federal, state, local and Navajo Nation tribal authorities. Delays or failures in obtaining regulatory approvals or permits or the receipt of an approval or permit with unreasonable conditions or costs could have a material adverse effect on our ability to exploit our properties. Additionally, the oil and gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Proposed GHG reporting rules and proposed GHG cap and trade legislation are two examples of proposed changes in the regulatory climate that would affect us. Furthermore, we may be placed at a competitive disadvantage to larger companies in the industry, which can spread these additional costs over a greater number of wells and larger operating staff. Please read *Business and Properties Environmental, Health and Safety Matters and Regulation* and *Business and Properties Other Regulation of the Oil and Gas Industry* for a description of the laws and regulations that affect us.

In addition, President Obama s budget and other legislative proposals would terminate various tax deductions currently available to companies engaged in oil and gas development and production. Tax deductions that are proposed to be terminated include the deduction for intangible drilling and development costs, the deduction for qualified tertiary injectant expenses, and the domestic manufacturing deduction. If enacted, the elimination of these deductions will adversely affect our business.

Proposed federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The U.S. Congress is currently considering legislation that would amend the Safe Drinking Water Act (SWDA) to eliminate an existing exemption from federal regulation of hydraulic fracturing activities and require the disclosure of chemical additives used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing is a common process in our industry of creating artificial cracks, or fractures, in deep underground rock formations through the pressurized injection of water, sand and other additives to enable fluids (including oil and gas) to move more easily through the rock to a production well. This process is often necessary to produce commercial quantities of oil and gas from many reservoirs, especially shale rock formations. We routinely utilize hydraulic fracturing techniques in many of our reservoirs. Currently, regulation of hydraulic fracturing is primarily conducted at the state level through permitting and other compliance requirements. If adopted, the proposed amendment to the SWDA could result in additional regulations and permitting requirements at the federal level. In addition, various states and localities are also studying or considering various additional regulatory measures related to hydraulic fracturing. Additional regulations and permitting requirements could lead to significant operational delays and increased operating costs, and make it more difficult to perform hydraulic fracturing.

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If we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules, our ability to produce oil and gas commercially and in commercial quantities could be impaired.

We use a substantial amount of water in our drilling operations. Our inability to locate sufficient amounts of water, or treat and dispose of water after drilling, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas. Furthermore, future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities of our proved reserves.

Our estimate of proved reserves at December 31, 2012, is based on the quantities of oil and gas that engineering and geological analyses demonstrate with reasonable certainty to be recoverable from established reservoirs in the future under current operating and economic parameters. NSAI audited the reserve and economic evaluations of all properties, except the New Permian Properties, that were prepared by us on a well-by-well basis. Oil and gas reserve engineering is not exact; it relies on subjective interpretations of data that may be inaccurate or incomplete and requires predictions and assumptions of future reservoir behavior and economic conditions. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including:

- the assumed accuracy of field measurements and other reservoir data;
- assumptions regarding expected reservoir performance relative to historical analog reservoir performance;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning the availability of capital and its costs;
- assumptions concerning future oil and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities of oil and gas that are ultimately recovered;
- the timing of the recovery of oil and gas reserves;
- the production and operating costs incurred; and

- the amount and timing of future development expenditures.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. As a result of all these factors, we may make material changes to reserves estimates to take into account changes in our assumptions and the results of our development activities and actual drilling and production.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly. In addition, if declines in oil and gas prices result in our having to make substantial downward adjustments to our estimated proved reserves, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to make downward adjustments, as a non-cash impairment charge to earnings, to the carrying value of our oil and gas properties. If we incur impairment charges in the future, we could have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our credit facility.

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The standardized measure of future net cash flows from our net proved reserves is based on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our proved reserves.

Actual future net cash flows from our oil and gas properties will be determined by the actual prices we receive for oil and gas, our actual operating costs in producing oil and gas, the amount and timing of actual production, the amount and timing of our capital expenditures, supply of and demand for oil and gas and changes in governmental regulations or taxation, which may differ from the assumptions used in creating estimates of future cash flows.

The timing of our production and our incurrence of expenses in connection with the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with guidance from the FASB may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Within the United States, we operate producing properties that are located in a limited number of geographic areas, making us vulnerable to risks associated with lack of geographic diversification.

Approximately 75% of our 2012 oil and gas revenues and total proved reserves at December 31, 2012, are located in our Aneth Field Properties in the southeast Utah portion of the Paradox Basin in the Four Corners area of the southwestern United States. Essentially all of the remainder of our sales of oil and gas and total proved reserves are attributable to the Wyoming, Bakken and Permian properties. As a result of our lack of diversification in asset type and location, any delays or interruptions of production from these wells caused by such factors as governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation of oil produced from the wells in these fields, price fluctuations, natural disasters or shutdowns of the pipelines connecting our Aneth Field production to refineries would have a significantly greater impact on our results of operations than if we possessed more diverse assets and locations.

Lack of geographic diversification also affects the prices to be received for our oil and gas production from our properties, since prices are determined to a significant extent by factors affecting the regional supply of and demand for oil and gas, including the adequacy of the pipeline and processing infrastructure in the region to transport or process our production and that of other producers. Those factors result in basis differentials between the published indices generally used to establish the price received for regional oil and gas production and the actual (frequently lower) price we may receive for our production.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are extended.

As of December 31, 2012, we had approximately 7,400 net acres in the Permian Basin, 12,600 net acres in the Bakken and 75,600 net acres in the Big Horn Basin that are not currently held by production. Unless production in paying quantities is established on units containing these leases during their primary terms or we obtain extensions of the leases, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based on various factors, including factors that are beyond our control, including drilling results, oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues, affect the timing and amounts of capital requirements and potentially result in a dilution of our respective ownership interest in the event we are unable to make any required capital contributions.

We do not operate all of the properties in which we have an interest. As a result, we may have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. For all of the properties that are operated by others, we are dependent on their decision-making with respect to day-to-day operations over which we have little control. The failure of an operator of wells in which we have an interest to adequately perform operations, or an operator s breach of applicable agreements, could reduce production and revenues we receive from that well. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the timing and amount of capital expenditures, the available expertise and financial resources, the inclusion of other participants and the use of technology.

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If the expenses associated with our joint venture partner s exploration activity exceed our current expectations or if our joint venture partner mobilizes additional drilling rigs in the future, we may be required to make significantly higher capital contributions to satisfy our proportionate share of the exploration costs. If such capital contributions are required, we may not be able to obtain the financing necessary to satisfy our obligations or we may have to reallocate our anticipated capital expenditure budget. In the event that we do not participate in future capital contributions with respect to this joint venture agreement or any other agreements relating to properties we do not operate, our respective ownership interest could be diluted.

Our derivative activities could reduce our net income.

To achieve more predictable cash flow and to reduce our exposure to adverse changes in the price of oil and gas, we have entered into, and plan to enter into in the future, derivative arrangements covering a significant portion of our oil and gas production. These derivative arrangements could result in both realized and unrealized derivative losses. Our derivative instruments are subject to mark-to-market accounting treatment, and the change in fair market value of the instrument is reported in our consolidated statements of income each quarter, which have resulted in, and will in the future likely result in, significant unrealized net gains or losses. We expect to continue to use derivative arrangements to reduce commodity price risk with respect to our estimated production from producing properties. Please read *Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations* and *Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures About Market Risk*.

Our actual future production during a period may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimates, it will have more unhedged production and therefore greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, whether due to issues with our sales to Western, natural declines in production and the failure to develop new reserves, the efficacy of our CO_2 project or other factors, we might be forced to satisfy all or a portion of our derivative transactions in cash without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction of our liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

In addition, our derivative activities are subject to the risk that a counterparty may not perform their obligation under the applicable derivative instrument. If derivative counterparties are unable to make payments to us under their derivative arrangements, our results of operations, financial condition and liquidity would be adversely affected.

The effectiveness of derivative transactions to protect us from future oil and gas price declines will be dependent upon oil and gas prices at the time we enter into future derivative transactions as well as our future levels of hedging, and as a result our future net cash flow may be more sensitive to commodity price changes.

As our derivatives expire, more of our future production will be sold at market prices unless we enter into additional derivative transactions. Our revolving credit facility prohibits us from entering into derivative arrangements for more than (i) 85% of our anticipated production from proved properties in the next two years and (ii) the greater of 75% of our anticipated production from proved properties or 85% of our production from projected proved developed producing reserves using economic parameters specified in our credit agreements. The prices at which we hedge our production in the future will be dependent upon commodity prices at the time we enter into these transactions, which may be substantially lower than current prices. Accordingly, our commodity price hedging strategy will not protect us from significant and sustained declines in oil and gas prices received for our future production. Conversely, our commodity price hedging strategy may limit our ability to realize cash flow from commodity price increases. It is also possible that a larger percentage of our future production will not be hedged as our derivative policies may change, which would result in our oil and gas revenue becoming more sensitive to commodity price changes.

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Legislation and regulation affecting derivative instruments could adversely affect our ability to hedge oil and gas prices which may increase our costs and adversely affect our profitability.

In July 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank). Dodd-Frank imposes restrictions on the use and trading of certain derivatives, including our oil and gas derivative instruments. The nature and scope of those restrictions will be determined in significant part through implementing regulations to be adopted by the SEC, the Commodities Futures Trading Commission and other regulators. We continue to assess the potential impact of the Dodd-Frank derivatives provisions on our operations and this assessment will be ongoing as the regulatory process contemplated by Dodd-Frank is further implemented. The effect of such future regulations on our business is uncertain.

In particular, note the following:

- Depending on the rules and definitions adopted by regulators, we could be required to post significant amounts of cash collateral with our dealer counterparties for our derivative transactions, which would likely make it impracticable to implement our current hedging strategy.

- If our ability to enter into derivative transactions is decreased as a result of Dodd-Frank, we would be exposed to additional risks related to commodity price volatility. Commodity price decreases would then have an immediate significant adverse effect on our profitability and revenues. Reduced derivative transactions may also impair our ability to have certainty with respect to a portion of our cash flow, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.

- We expect that the cost to enter into derivative transactions will increase as a result of a reduction in the number of counterparties in the market and the pass-through of increased counterparty costs, thereby increasing the costs of derivative instruments. Our derivatives counterparties may be subject to significant new capital, margin and business conduct requirements imposed as a result of the new legislation.

- Dodd-Frank contemplates that most swaps will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. While we may ultimately be eligible for such exceptions, the scope of these exceptions currently is uncertain, pending further definition through rule making proceedings.

- The above factors could also affect the pricing of derivatives and make it more difficult for us to enter into hedging transactions on favorable terms.

The nature of our assets expose us to significant costs and liabilities with respect to environmental and operational safety matters. We are also responsible for costs associated with the removal and remediation of the decommissioned Aneth Gas Processing Plant.

We may incur significant costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and gas exploration, production and other activities. These costs and liabilities could arise under a wide range of environmental, health and safety laws and regulations, including agency interpretations thereof and governmental enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory, cleanup and site restoration costs and liens, the denial or revocation of permits or other authorizations and the issuance of injunctions to limit or cease operations. Compliance with these laws and regulations also increases the cost of our operations and may prevent or delay the commencement or continuance of a given operation. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

We have an interest in the Aneth Gas Processing Plant, which is currently being decommissioned. Under our purchase agreement with Chevron, Chevron is responsible for indemnifying us against the decommissioning and clean-up or remediation costs allocable to the 39% interest we purchased from it. Under our purchase agreement with ExxonMobil, however, we are responsible for the decommissioning and clean-up or remediation cost allocable to the interests we purchased from ExxonMobil, which is 25% of the total cost of the project. If Chevron fails to pay its share of the decommissioning costs in accordance with the purchase agreement, we could be held responsible for 64% of the total costs to decommission and remediate the Aneth Gas Processing Plant. Chevron is managing the decommissioning process and, based on our current estimate, the total cost of the decommissioning is $26.3 million. $25.5 million has already been incurred and paid for as of December 31, 2012. This estimate does not include any costs for any possible subsurface clean-up or remediation of the site, which may be significant.

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The Aneth Gas Processing Plant site was previously evaluated by the U.S. EPA for possible listing on the National Priorities List (NPL) of sites contaminated with hazardous substances with the highest priority for clean-up under the CERCLA. Based on its investigation, the EPA concluded no further investigation was warranted and that the site was not required to be listed on the NPL. The Navajo Nation Environmental Protection Agency now has primary jurisdiction over the Aneth Gas Processing Plant site, however, and we cannot predict whether it will require further investigation and possible clean-up, and the ultimate cleanup liability may be affected by the recent enactment by the Navajo Nation of the Navajo CERCLA. In some matters, the Navajo CERCLA imposes broader obligations and liabilities than the federal CERCLA. We have been advised by Chevron that a significant portion of the subsurface clean-up or remediation costs, if any, would be covered by an indemnity from the prior owner of the plant, and Chevron has provided us with a copy of the pertinent purchase agreement that appears to support Chevron s position. We cannot predict whether any subsurface remediation will be required or what the costs of the subsurface clean-up or remediation could be. Additionally, we cannot be certain whether any of such costs will be reimbursable to us pursuant to the indemnity of the prior owner. To the extent any such costs are incurred and not reimbursed pursuant to the indemnity from the prior owner, we would be liable for 25% of such costs as a result of our acquisition of the ExxonMobil Properties. Please read *Business and Properties Aneth Gas Processing Plant* for additional information about this liability.

Strict or joint and several liability to remediate contamination may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Please read *Business and Properties Environmental, Health and Safety Matters and Regulation* for more information.

We may be unable to compete effectively with larger companies, which may adversely affect our operations and ability to generate and maintain sufficient revenue.

The oil and gas industry is intensely competitive, and we compete with companies that have greater resources, including an increased ability to attract, compensate and retain quality employees. Many of these companies not only explore for and produce oil and gas, but also refine and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration or exploitation activities during periods of low oil and gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

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

Certain studies have suggested that emissions of GHG, including CO_2 and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of GHG. In addition, several states have already taken legal measures to reduce emissions of GHG. As a result of the U.S. Supreme Court s decision on April 2, 2007, in *Massachusetts, et al. v. EPA*, the EPA also may be required to regulate GHG emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of GHG. Other nations have already agreed to regulate emissions of GHG, pursuant to the United Nations Framework Convention on Climate Change, and the subsequent Kyoto Protocol, an international treaty pursuant to which participating countries (not including the United States) agreed to reduce their emissions of GHG to below 1990 levels by 2012. A successor treaty to the Kyoto Protocol has not been developed to date. Passage of state or federal climate control legislation or other regulatory initiatives or the adoption of regulations by the EPA and state agencies that restrict emissions of GHG in areas in which we conduct business could have an adverse effect on our operations and demand for oil and gas.

Recently approved final rules regulating air emissions from gas processing operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

On April 17, 2012, the EPA issued final rules that established new air emission controls for oil and gas production and gas processing operations. These rules were published in the Federal Register on August 16, 2012. Specifically, the EPA s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and VOC and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and gas production and procession activities. The final rule includes a 95% reduction in VOC emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules could require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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We depend on a limited number of key personnel who would be difficult to replace.

We depend substantially on the performance of our executive officers and other key employees. We have entered into employment agreements with certain of these employees, but we do not maintain key personnel life insurance policies on any of these employees. The loss of any member of the senior management team or other key employees could negatively affect our ability to execute our business strategy.

Work stoppages, protests or other labor issues at our facilities could adversely affect our business, financial position, results of operations, or cash flows.

As of December 31, 2012, 55 of our field level employees were represented by the USW, and covered by a collective bargaining agreement. Although we believe that our relations with our employees are generally satisfactory, if we are unable to reach agreement with any of our unionized work groups on future negotiations regarding the terms of their collective bargaining agreements, or if additional segments of our workforce become unionized, we may be subject to work interruptions or stoppages. In addition, work stoppages have occurred in the past as a result of protests by local tribal members. Work stoppages at the facilities of our customers or suppliers may also negatively affect our business. If any of our customers experience a material work stoppage, the customer may halt or limit the purchase of our products. Moreover, if any of our suppliers experience a work stoppage, our operations could be adversely affected if an alternative source of supply is not readily available. Any of these events could be disruptive to our operations and could adversely affect our business, financial position, results of operations, or cash flows.

We may be required to write down the carrying value of our properties in the future.

We use the full cost accounting method for oil and gas exploitation, development and exploration activities. Under the full cost method rules, we perform a ceiling test and if the net capitalized costs for a cost center exceed the ceiling for the relevant properties, we write down the book value of the properties. Accordingly, we could recognize impairments in the future if oil and gas prices are low, if we have substantial downward adjustments to our estimated proved reserves, if we experience increases in our estimates of development costs or deterioration in our exploration and development results.

Terrorist attacks aimed at our facilities or operations could adversely affect our business.

The United States has been the target of terrorist attacks of unprecedented scale. The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any terrorist attack at our facilities, or those of our customers or suppliers, could have a material adverse effect on our business.

We are subject to cyber security risks.

A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss. The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering transportation systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. Pipelines, refineries, power stations and distribution points for both fuels and electricity are becoming interconnected by computer systems. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners may become the target of cyber attacks or information security breaches that could result in unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of business operations. In addition, certain cyber incidents may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. Although to date we have not experienced any material losses relating to cyber attacks, we may suffer such losses in the future. We may be required to expend significant resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

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Compliance with the Sarbanes-Oxley Act of 2002 and other obligations of being a public company requires substantial financial and management resources.

Section 404 of the Sarbanes-Oxley Act of 2002, or the Sarbanes-Oxley Act, requires that we evaluate and report on our system of internal controls. If we fail to maintain the adequacy of our internal controls, we could be subject to regulatory scrutiny, civil or criminal penalties and/or stockholder litigation. Any inability to provide reliable financial reports could harm our business. Section 404 of the Sarbanes-Oxley Act also requires that our independent registered public accounting firm report on management s evaluation of the Company s system of internal controls. Any failure to maintain the adequacy of our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Inferior internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of the shares of our common stock.

Our plans for future strategic acquisitions may require substantial capital, which we may be unable to obtain on favorable terms and which is likely to require us to incur additional financing indebtedness.

Our industry is capital intensive, and one component of our strategy has been to grow our reserves and production by acquiring domestic onshore properties. We have expressed the intent to acquire the Option Properties and continue to actively evaluate the acquisition of properties that are prospective for production of oil and NGL, particularly in the Permian Basin and Rocky Mountain regions. Future acquisitions that we may pursue may require us to incur additional financing indebtedness and leverage our existing assets. To date, we have financed such acquisitions primarily with proceeds from bank borrowings under our credit facility, cash generated by operations and the issuance of Notes. We intend to finance future acquisitions utilizing similar financing sources, which may include amending our credit facility and expanding the borrowing base and the sale of equity or debt securities. There can be no assurance as to the availability of any additional financing or that the terms will be acceptable to us. Our inability to obtain additional financing or sufficient financing on favorable terms may adversely affect our growth, competitiveness and profitability. Further, the incurrence of substantial indebtedness could have material adverse effects on our financial condition and liquidity and limit our future flexibility and growth opportunities.

Our substantial indebtedness could adversely affect our business, results of operations and financial condition.

In addition to making it more difficult for us to satisfy our obligations to pay principal and interest on our outstanding indebtedness, our substantial indebtedness could limit our ability to respond to changes in the markets in which we operate and otherwise limit our activities. For example, our indebtedness, and the terms of agreements governing that indebtedness, could:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt obligations, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;

- increase our vulnerability to economic downturns and impair our ability to withstand sustained declines in oil and gas prices;

- subject us to covenants that limit our ability to fund future working capital, capital expenditures, exploration costs and other general corporate requirements;

- prevent us from borrowing additional funds for operational or strategic purposes (including to fund future acquisitions), disposing of assets or paying cash dividends;

- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;

- require us to devote a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow to fund exploration efforts, working capital, capital expenditures and other general corporate purposes; and

place us at a competitive disadvantage relative to our competitors that have less debt outstanding.

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Covenants in the indenture governing the Notes and in our revolving credit facility currently impose, and future financing agreements may impose, significant operating and financial restrictions.

The indenture governing the Notes and our revolving credit facility contain restrictions, and future financing agreement may contain additional restrictions, on our activities, including covenants that restrict our and our restricted subsidiaries ability to:

- incur additional debt;
- pay dividends on, redeem or repurchase stock;
- create liens;
- make specified types of investments;
- apply net proceeds from certain asset sales;
- engage in transactions with our affiliates;
- engage in sale and leaseback transactions;
- merge or consolidate;
- restrict dividends or other payments from restricted subsidiaries;
- sell equity interests of restricted subsidiaries; and
- sell, assign, transfer, lease, convey or dispose of assets.

Our revolving credit agreement will mature in April 2017, unless extended, and is secured by all of our oil and gas properties as well as a pledge of all ownership interests in operating subsidiaries. The revolving credit facility contains various affirmative and negative covenants including but not limited to financial covenants that (i) require us to maintain a consolidated current ratio of at least 1.0 to 1.0 at the end of any fiscal quarter, and (ii) we may not permit our maximum leverage ratio (consolidated indebtedness to consolidated EBITDA as defined in the credit agreement) to exceed 4.0 to 1.0 at the end of each fiscal quarter, except the fourth quarter of 2012 where it may not exceed 4.25 to 1.0.

These restrictions may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We may also incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility. We cannot assure you that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all.

Availability under our revolving credit facility depends on a borrowing base which is subject to redetermination by our lenders. If our borrowing base is reduced, we may be required to repay amounts outstanding under our revolving credit facility.

Under the terms of our revolving credit facility, our borrowing base (currently set at $330 million) is subject to semi-annual redetermination by our lenders based on their valuation of our proved reserves and their internal criteria. In addition, under certain circumstances, interim redeterminations may be conducted. In the event the amount outstanding under our revolving credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. If we do not have sufficient funds on hand for repayment, we may be required to seek a waiver or amendment from our lenders, refinance our revolving credit facility, sell assets or sell additional shares of common stock. We may not be able obtain such financing or complete such transactions on terms acceptable to us or at all. Failure to make the required repayment could result in a default under our revolving credit facility.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our revolving credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase although the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness would decrease.

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Delaware law and our amended and restated charter documents may impede or discourage a takeover that our stockholders may consider favorable.

Our amended and restated charter and bylaws have provisions that may deter, delay or prevent a third party from acquiring us. These provisions include:

- limitations on the ability of stockholders to amend our charter documents, including stockholder supermajority voting requirements;
- the inability of stockholders to act by written consent or to call special meetings;
- a classified board of directors with staggered three-year terms;
- the authority of our board of directors to issue, without stockholder approval, up to 1,000,000 shares of preferred stock with such terms as the board of directors may determine and to issue additional shares of our common stock; and
- advance notice procedures with respect to stockholder proposals and the nomination of candidates for election as directors.

Stock prices of equity securities can be volatile, and there is no assurance that a purchaser of our common stock will be able to resell the common stock purchased at a price in excess of the purchase price.

Over the past several years, the stock prices of companies on the U.S. securities markets have been volatile, increasing or decreasing not in response to the company financial or operating results, but the general economic trends or events. In addition, stock prices of companies in the oil and gas industry in which we operate are significantly affected by commodity prices for oil and gas. In particular, our stock price was very volatile during 2012, trading between $12.12 and $7.75. All of these factors are beyond our control, and could have drastic impacts occurring within short periods of time. These factors could cause a decrease in the stock price following purchase, and a purchaser of our stock may not be able to sell their common stock for price exceeding the purchase price

Offers or availability for resale of a substantial number of shares of our common stock or exercise of outstanding Warrants would result in dilution to our stockholders and might have an adverse effect on the market price of our common stock.

If our warrant holders exercise outstanding warrants and sell substantial amounts of our common stock in the public market, or if our stockholders resell substantial amounts of our common stock pursuant to a registration statement or Rule 144 under the Securities Act of 1933, as amended (the Securities Act), such resales could create a circumstance commonly referred to as an overhang and in anticipation of which the market price of our common stock could fall. The existence of an overhang, whether or not sales have occurred or are occurring, also could exert downward pressure on our stock price and make it more difficult for us to raise additional financing through the sale of equity or equity-related securities in the future at a time and price that we deem reasonable or appropriate. At December 31, 2012, we had outstanding warrants to purchase 33.0 million shares of common stock at an exercise price of $13.00 per share, representing approximately 35% of our outstanding common stock at such date. Exercise of these warrants would result in dilution to our stockholders, which could cause the market price of our common stock to decline. In addition, the resale of shares under our existing resale registration statement or pursuant to the exercise of registration rights covering an additional 4.3 million shares of our common stock could further adversely affect the market price of our common stock or impact our ability to raise additional equity capital. At February 28, 2013, an aggregate of 33 million warrants are exercisable at an exercise price of $13.00 per share. Outstanding warrants at such date represented approximately 35% of our total capitalization, assuming full exercise of the warrants. We are unable to predict the amount or timing of future exercises.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are not a party to any material pending legal or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any of our pending proceedings will not have a material adverse effect on our financial condition or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Price Range of Common Stock and Number of Holders

Our common stock is listed on the New York Stock Exchange under the symbol REN . The following table sets forth the high and the low sale prices per share of our common stock for the twelve months ended December 31, 2012 and 2011. The closing price of the common stock on February 28, 2013 was $10.18.

	2012		2011	
Period	**High**	**Low**	**High**	**Low**
1st Quarter	$ 12.12	$ 9.74	$ 18.43	$ 14.56
2nd Quarter	$ 11.62	$ 8.09	$ 18.55	$ 15.15
3rd Quarter	$ 10.00	$ 8.12	$ 17.50	$ 11.19
4th Quarter	$ 9.08	$ 7.75	$ 14.24	$ 10.44

As of February 28, 2013, there were approximately 205 record holders of our common stock.

Our warrants are listed on the New York Stock Exchange under the symbol RENWS . The following table sets forth the high and the low sale prices per share of our warrants for the twelve months ended December 31, 2012 and 2011. The closing price of the warrants on February 28, 2013 was $0.83

	2012		2011	
Period	**High**	**Low**	**High**	**Low**
1st Quarter	$ 1.84	$ 0.95	$ 5.50	$ 3.17
2nd Quarter	$ 1.54	$ 1.49	$ 5.53	$ 2.97
3rd Quarter	$ 1.06	$ 0.97	$ 4.62	$ 1.39
4th Quarter	$ 0.82	$ 0.79	$ 3.04	$ 1.25

Issuer Purchases of Equity Securities

In connection with the vesting of company restricted common stock under the 2009 Long Term Performance Incentive Plan (Incentive Plan), we retain shares of common stock at the election of the recipients of such awards in satisfaction of withholding tax obligations. These shares are retired by the Company.

2012	**Total Number of Shares Purchased(1)**	**Average Price Paid Per Share**	**Total Number of Shares Purchased as Part of Publically Announced Plan**	**Maximum Number of Shares That May Yet Be Purchased Under The Plan(2)**
June	1,636	$ 8.85		
August	9,850	$ 8.54		
November	248	$ 8.04		
December	125,956	$ 8.13		

1) All shares purchased in 2012 were to offset tax withholding obligations that occur upon the vesting and delivery of outstanding common shares under the terms of the Incentive Plan.
2) As of December 31, 2012, the maximum number of shares that may yet be purchased would not exceed the employees portion of taxes withheld on unvested shares (2,072,782 common shares) and the shares yet to be granted under the Incentive Plan (5,757,608 common shares).

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Dividend Policy

We have not declared any cash dividends on our common stock since inception and have no plans to do so in the foreseeable future. The ability of our Board of Directors to declare any dividend is subject to limits imposed by the terms of our credit agreement and our indenture covering the Notes, which currently prohibit us from paying dividends on our common stock. Our ability to pay dividends is also subject to limits imposed by Delaware law. In determining whether to declare dividends, the Board of Directors will consider the limits imposed by the credit agreement, financial condition, results of operations, working capital requirements, future prospects and other factors it considers relevant.

Comparison of Cumulative Return

The following graph compares the cumulative return on a $100 investment in Resolute common stock from September 28, 2009, the date the common stock began trading on the New York Stock Exchange, through December 31, 2012, to that of the cumulative return on a $100 investment in the Russell 2000 Index and the S&P 500 Energy Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed. The indices are included for comparative purpose only. This graph is not soliciting material, is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing.

COMPARISON OF CUMULATIVE TOTAL RETURN

AMONG RESOLUTE ENERGY CORPORATION, THE RUSSELL 2000 INDEX

AND THE S&P 500 ENERGY INDEX

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ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial data for the years ended December 31, 2012, 2011, 2010, 2009 and 2008. The consolidated balance sheet and income statement information are derived from our audited financial statements. On September 25, 2009, Hicks Acquisition Company I, Inc. (HACI), consummated a business combination under the terms of a Purchase and IPO Reorganization Agreement with us and Resolute Holdings Sub, LLC, whereby, through a series of transactions, HACI s stockholders collectively acquired a majority of our outstanding shares of common stock. Immediately prior to the consummation of such merger transaction, we owned, directly or indirectly, 100% of the equity interests of Resolute Natural Resources Company, LLC, WYNR, LLC, BWNR, LLC, RNRC Holdings, Inc., and Resolute Wyoming, Inc. (formerly known as Primary Natural Resources, Inc.), and owned a 99.996% equity interest in Resolute Aneth, LLC. We collectively refer to Resolute and each of the subsidiaries set forth above as Predecessor Resolute. The entities composing Predecessor Resolute prior to the merger transaction with HACI were wholly owned by Resolute Holdings Sub, LLC (except for Resolute Aneth, LLC, which was owned 99.996% by Resolute Holdings Sub, LLC), which in turn is a wholly owned subsidiary of Resolute Holdings, LLC. Effective December 31, 2010, Resolute Aneth, LLC became our wholly-owned subsidiary.

HACI was the accounting acquirer of Resolute in September 2009, and accordingly, the historical financial data below reflects HACI through the date of the acquisition. Our results of oil and gas operations are reflected from the date of the acquisition in September 2009. Future results may differ substantially from historical results because of changes in oil and gas prices, production increases or declines and other factors. This information should be read in conjunction with our consolidated financial statements and related notes and *Management s Discussion and Analysis of Financial Condition and Results of Operations* presented elsewhere in this report.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(in thousands, except per share data)				
Statement of Operation Data:					
Revenue	$ 258,268	$ 226,908	$ 173,395	$ 42,416	$
Operating expenses	218,084	169,473	142,225	57,361	1,560
Income (loss) from operations	40,184	57,435	31,170	(14,945)	(1,560)
Other income (expense)	(10,327)	(9,080)	(22,597)	(50,185)	7,601
Income (loss) before income taxes	29,857	48,355	8,573	(65,130)	6,041
Income tax benefit (expense)	(11,881)	(17,870)	(2,388)	19,887	(2,054)
Net income (loss)	17,976	30,485	6,185	(45,243)	3,987
Earnings (loss) per share:					
Common stock, subject to redemption	$	$	$	$ (0.16)	$ 0.09
Common stock, basic	$ 0.30	$ 0.53	$ 0.12	$ (0.93)	$ 0.06
Common stock, diluted	$ 0.30	$ 0.47	$ 0.12	$ (0.93)	$ 0.06
Weighted average shares outstanding:					
Common stock, subject to redemption				12,114	16,560
Common stock, basic	59,424	57,612	49,900	46,394	45,105
Common stock, diluted	59,452	65,029	50,475	46,394	45,105
Selected Cash Flow Data:					
Net cash provided by (used in) operating activities	$ 76,771	$ 101,087	$ 58,495	$ (12,164)	$ 3,031
Net cash provided by (used in) investing activities	(447,447)	(217,006)	(69,123)	209,987	(2,264)
Net cash provided by (used in) financing activities	370,475	115,210	12,017	(198,197)	

	As of December 31,				
	2012	2011	2010	2009	2008
	(in thousands)				
Balance Sheet Data:					
Total assets	$ 1,364,130	$ 947,560	$ 760,523	$ 693,440	$ 544,797
Long term debt	563,865	170,000	127,900	109,575	
Total liabilities	831,946	431,735	356,657	299,903	19,294
Stockholders equity	532,184	515,825	403,866	393,537	362,199

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Overview

The following discussion and analysis should be read in conjunction with the consolidated financial statements and the related notes contained elsewhere in this report. We are an independent oil and gas company engaged in the acquisition, exploration, development and production of oil, gas and hydrocarbon liquids and plan to grow through exploration, exploitation and industry standard enhanced oil recovery projects.

As of December 31, 2012, we estimated net proved reserves were approximately 78.8 MMBoe, of which approximately 43% were proved developed producing reserves and approximately 79% were oil. The standardized measure of our estimated net proved reserves as of December 31, 2012 was $872 million. We focused our efforts on increasing reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flow from existing operations are dependent on a variety of factors including commodity prices, exploitation and recovery activities and our ability to manage our overall cost structure at a level that allows for profitable operation.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our operating performance, including but not limited to, production levels, pricing and cost trends, reserve trends, operating and general and administrative expenses, operating cash flow and Adjusted EBITDA (defined below).

Production Levels, Trends and Prices. Oil and gas revenue is the product of our production multiplied by the price that we receive for that production. Because the price that we receive is highly dependent on many factors outside of our control, except to the extent that we have entered into derivative arrangements that can influence our net price either positively or negatively, production is the primary revenue driver over which we have some influence. Although we cannot greatly alter reservoir performance, we can aggressively implement exploitation activities that can increase production or diminish production declines relative to what would have been the case without intervention. Examples of activities that can positively influence production include minimizing production downtime due to equipment malfunction, well workovers and cleanouts, recompletions of existing wells in new parts of the reservoir and expanded secondary and tertiary recovery programs.

The price of oil has been extremely volatile, and we expect that volatility to continue. Given the inherent volatility of oil prices, we plan our activities and budget based on sales price assumptions that we believe to be reasonable. We use derivative contracts to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices and currently have such contracts in place through 2014. These instruments limit our exposure to declines in prices, but also limit our ability to receive the benefit of price increases. Changes in the price of oil or gas will result in the recognition of a non-cash gain or loss recorded in other income or expense due to changes in the future fair value of the derivative contracts. Recognized gains or losses only arise from payments made or received on monthly settlements of derivative contracts or if a derivative contract is terminated prior to its expiration. We typically enter into derivative contracts that cover a significant portion of our estimated future oil and gas production.

Reserve Trends. From inception, we have grown our reserve base through a focused acquisition strategy. We acquired the majority of our Aneth Field Properties through two significant purchases from Chevron and ExxonMobil in November 2004 and April 2006, respectively. We acquired our Wyoming Properties in July 2008, our Bakken Properties in 2010 and 2011, our Permian Properties in 2011and 2012 and Denbury s interest in the Aneth Field Properties in 2012. We plan to continue to seek opportunities to acquire similar producing properties that have upside potential through low-risk development drilling and exploitation projects, and believe that our knowledge of various domestic onshore operating areas, strong management and staff and solid industry relationships will allow us to locate, capitalize on and integrate strategic acquisition opportunities.

At December 31, 2012, we have estimated net proved reserves of approximately 45 MMBoe that were classified as proved developed non-producing and proved undeveloped. An estimated 34.5 MMBoe, or 77%, of those reserves are attributable to recoveries associated with expansions, extensions and processing of the tertiary recovery CO_2 floods that are in operation on the Aneth Field Properties. We believe that the expenditures associated with the CO_2 floods will result in significant increases in Aneth Field oil and gas production.

Operating Expenses. Operating expenses consist of costs associated with the operation of oil and gas properties and production and ad valorem taxes. Direct labor, repair and maintenance, workovers, utilities, disposal activities, fluids and chemicals and contract services comprise the most significant portion of lease operating expenses. We monitor our operating expenses in relation to production amounts and the number of wells operated. Some of these expenses are relatively independent of the volume of hydrocarbons produced, but may fluctuate depending on the activities performed during a specific period. Other expenses, such as taxes and utility costs, are more directly related to production volumes or reserves. Severance taxes, for example, are charged based on production revenue and therefore are based on the product of the volumes that are sold and the related price received. Ad valorem taxes are generally based on the value of reserves. Because we operate on the Navajo Reservation, we also pay a possessory interest tax, which is effectively an ad valorem tax assessed by the Navajo Nation. Our largest utility expense is for electricity that is used primarily to power the pumps in producing wells and the compressors behind the injection wells. The more fluid that is moved, the greater the amount of electricity that is consumed. Higher oil prices can lead to higher demand for drilling rigs, workover rigs, operating personnel and field supplies and services, which in turn can increase the costs of those goods and services.

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General and Administrative Expenses. We monitor our general and administrative expenses carefully, attempting to balance costs against the benefits of, among other things, hiring and retaining highly qualified staff who can add value to our asset base. General and administrative expenses include, among other things, salaries and benefits, share-based compensation, general corporate overhead, fees paid to independent auditors, lawyers, petroleum engineers and other professional advisors, costs associated with shareholder reports, investor relations activities, registrar and transfer agent fees, director and officer liability insurance costs and director compensation.

Operating Cash Flow. Operating cash flow is the cash directly derived from our oil and gas properties, before considering such things as administrative expenses and interest costs. Operating cash flow per unit of production is a measure of field efficiency, and can be compared to results obtained by operators of oil and gas properties with characteristics similar to ours in order to evaluate relative performance. Aggregate operating cash flow is a measure of our ability to sustain overhead expenses and costs related to capital structure, including interest expenses.

Adjusted EBITDA. We define adjusted EBITDA (a non-GAAP measure) as consolidated net income adjusted to exclude interest expense, interest income, income taxes, depletion, depreciation and amortization, impairment expense, accretion of asset retirement obligation, change in fair value of derivative instruments, early settlement of derivative instruments, non-cash share-based compensation expense and noncontrolling interest amounts. Adjusted EBITDA is a financial measure that we report to our lenders and is used as a gauge for compliance with some of the financial covenants under our revolving credit facility.

Adjusted EBITDA is also used as a supplemental liquidity or performance measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the ability of our assets to generate cash sufficient to pay interest costs;
- the financial metrics that support our indebtedness;
- our ability to finance capital expenditures;
- financial performance of the assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to those of other companies in the exploration and production industry, without regard to financing methods or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance, liquidity or ability to service debt obligations. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate gross margins. Because we use capital assets, depletion, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net income and net cash provided by operating activities determined under GAAP, as well as Adjusted EBITDA, when evaluating our financial performance and liquidity. Adjusted EBITDA excludes some, but not all, items that affect net income, operating income and net cash provided by operating activities and these measures may vary among companies. Our Adjusted EBITDA may not be comparable to Adjusted EBITDA of any other company because other entities may not calculate Adjusted EBITDA in the same manner.

Factors That Significantly Affect Our Financial Results

Revenue, cash flow from operations and future growth depend on many factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Historical oil prices have been volatile and are expected to fluctuate widely in the future. Sustained periods of low prices for oil could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas that we can economically produce, and our ability to obtain capital.

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Like all businesses engaged in the exploration for and production of oil and gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and gas production from a given well decreases. Thus, an oil and gas exploration and production company depletes part of its asset base with each unit of oil or gas it produces. We attempted to overcome this natural decline by developing existing properties, implementing secondary and tertiary recovery techniques and by acquiring more reserves than we produced. Our future growth will depend on our ability to enhance production levels from existing reserves and to continue to add reserves in excess of production through exploration, development and acquisition. We will maintain our focus on costs necessary to produce our reserves as well as the costs necessary to add reserves through production enhancement, drilling and acquisitions. Our ability to make capital expenditures to increase production from existing reserves and to acquire more reserves is dependent on availability of capital resources, and can be limited by many factors, including the ability to obtain capital in a cost-effective manner and to obtain permits and regulatory approvals in a timely manner.

2013 Guidance

The following table summarizes our current financial and operational estimates for 2013.

	Range	
Projected total production (MBoe)	4,275	4,725
Boe per day	11,700	13,000
Projected costs		
Lease operating expense ($ million)(1)	$95	$105
General and administrative ($ million)(1)	$22	$24
Production and related taxes (% of production revenue)	12.5%	13.0%
Depletion, depreciation and amortization ($ per Boe)	$24.00	$26.00
Projected capital expenditures ($ million)	$145	$165
Aneth Field (excluding CO_2)	$50	$58
Aneth Field CO_2	$20	$22
Permian Properties	$50	$55
Bakken Properties	$15	$20
Other	$10	

(1) Excludes non-cash items.

Please read *Quantitative and Qualitative Disclosures about Market Risk* *Commodity Price Risk and Derivative Arrangements* which summarizes our derivative positions for 2013.

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Results of Operations

For the purposes of management s discussion and analysis of the results of operations, management has analyzed the operational results for the twelve months ended December 31, 2012, in comparison to results for the twelve months ended December 31, 2011 and 2010.

The following table presents our sales volumes, revenues and operating expenses, and sets forth our sales prices, costs and expenses on a Boe basis for 2012, 2011 and 2010.

	Twelve Months Ended December 31,		
	2012	2011	2010
	(in thousands, except where indicated)		
Net Sales:			
Total sales (MBoe)	3,409	2,924	2,730
Average daily sales (Boe/d)	9,313	8,012	7,478
Revenue:			
Revenue from oil and gas activities	$ 258,268	$ 226,908	$ 173,395
Operating Expenses:			
Lease operating	$ 79,922	$ 59,516	$ 51,618
Production and ad valorem taxes	35,716	31,379	24,151
General and administrative	24,032	20,914	19,440
General and administrative (excluding non-cash compensation expense)	15,297	13,489	13,499
Depletion, depreciation, amortization and accretion	78,414	57,664	47,016
Other Income (Expense):			
Interest expense	$ (15,523)	$ (3,844)	$ (4,855)
Realized and unrealized gain (loss) on derivative instruments	5,176	(5,321)	(17,842)
Income tax expense	(11,881)	(17,870)	(2,388)
Average Sales Prices ($/Boe):			
Average sales price (excluding derivative settlements)	$ 75.77	$ 77.60	$ 63.52
Operating Expenses ($/Boe):			
Lease operating	$ 23.45	$ 20.35	$ 18.91
Production and ad valorem taxes	10.48	10.73	8.85
General and administrative	7.05	7.15	7.12
General and administrative (excluding non-cash compensation expense)	4.49	4.61	4.95
Depletion, depreciation, amortization and accretion	23.00	19.72	17.22

Year Ended December 31, 2012, Compared to the Year Ended December 31, 2011

Revenue. Revenue from oil and gas activities increased to $258.3 million during 2012, from $226.9 million during 2011. The $31.4 million increase in revenue was attributable to $37.6 million in increased production, offset by $6.2 million in commodity price decreases ($77.60 per Boe in 2011 versus $75.77 per Boe in 2012). Sales volumes in 2012 increased 17% as compared to 2011, from 2,924 MBoe to 3,409 MBoe, primarily as a result of increased production from the Bakken and Permian Properties due to a higher number of producing wells compared to 2011 and additional production in Aneth Field resulting from increased CO_2 flood response and workover activity.

Operating Expenses. Lease operating expenses increased to $79.9 million during 2012, from $59.5 million during 2011. The $20.4 million, or 34%, increase was due to expanded operations in the Bakken and Permian Properties, increased repair and workover activity in Aneth Field to restore wells to production and the expense attributable to the additional working interests in Aneth Field purchased from Denbury. On a unit of production basis, lease operating expense increased 15% from $20.35 per Boe in 2011 to $23.45 per Boe in 2012.

Production and ad valorem taxes increased by 14% to $35.7 million during 2012, versus $31.4 million during 2011, mainly due to the increase in production during 2012. Production and ad valorem taxes were 14% of total revenue in 2012 and 2011.

Depletion, depreciation, amortization and accretion expenses increased to $78.4 million during 2012, as compared to $57.7 million during 2011. The $20.7 million, or 36%, increase is principally due a higher depletable base, higher finding costs and increased production in 2012.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. No provision for impairment was recorded in 2012 or 2011.

General and administrative expenses increased to $24.0 million during 2012, as compared to $20.9 million during 2011. The $3.1 million, or 15%, increase resulted from increased salaries and wages associated with expanded operations, increased share-based compensation expense and professional service fees, offset by increased overhead billings and capitalized expense. Cash-based general and administrative expense was $15.3 million, or $4.49 per Boe in 2012, compared to $13.5 million, or $4.61 per Boe in 2011. Share-based compensation expense represented $8.7 million, or $2.56 per Boe, during 2012 and $7.4 million, or $2.54 per Boe, during 2011.

Other Income (Expense). All oil and gas derivative instruments are accounted for under mark-to-market accounting rules, which provide for the fair value of the contracts to be reflected as either an asset or a liability on the balance sheet. The change in the fair value during an accounting period is reflected in the income statement for that period. During 2012, the realized and unrealized gains on our oil and gas derivatives totaled $5.2 million. This amount included $22.9 million of realized losses, including $3.4 million of partial terminations of certain derivative contracts, offset by $28.1 million of increases in the unrealized fair value of oil and gas derivatives. During 2011, the realized and unrealized losses on oil and gas derivatives totaled $5.3 million, including $20.8 million of realized losses in the fair value of oil and gas derivatives, of which $5.0 million was related to partial terminations of certain derivative contracts, offset by $15.5 million of unrealized gains.

Interest expense was $15.5 million during 2012 as compared to $3.8 million during 2011. The $11.7 million, or 304%, increase is attributable to the issuance in 2012 of our Senior Notes, which carry a significantly higher interest rate than that of our credit facility debt outstanding during 2011, and to a higher average debt balance during 2012.

Income Tax Benefit (Expense). Income tax expense recognized during 2012 was $11.9 million, or 40% of income before income taxes, as compared to income tax expense of $17.9 million, or 37% of income before income taxes in 2011. The increase in the effective tax rate over 2011 is the result of permanent differences related to share-based compensation. Income tax expense differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% due to state income taxes and estimated permanent differences. We carried a $10.8 million current deferred tax asset at December 31, 2012, for which no valuation allowance was recorded as it is more likely than not that the asset will be realized due to projected future taxable income.

Year Ended December 31, 2011, Compared to the Year Ended December 31, 2010

Revenue. Revenue from oil and gas activities increased to $226.9 million during 2011, from $173.4 million during 2010. Of the $53.5 million increase in revenue, approximately $41.1 million was attributable to higher commodity prices, while $12.4 million was attributable to increased production. Average sales price, excluding derivative settlements, increased from $63.52 per Boe in 2010 to $77.60 per Boe in 2011, primarily as a function of increased commodity pricing. Sales volumes increased 7% during 2011 as compared to 2010, from 2,730 MBoe to 2,924 MBoe. The 2010 well recompletion program and increased response from the Company s CO_2 flood projects in the Aneth Field Properties were the primary drivers of the production increase. The additional increase was due to production related to the Bakken Properties, although we did not begin drilling activities in North Dakota until the end of the third quarter of 2010, and production attributable to the Permian Properties beginning in August 2011.

Operating Expenses. Lease operating expenses increased to $59.5 million during 2011, from $51.6 million during 2010, a portion of which was due to expanded operations in new areas. The $7.9 million, or 15%, increase was primarily attributable to $4.9 million in increased equipment, maintenance and supplies, $1.9 million in increased utilities and fuel due to increased compression capability and additional fuel purchases in the Aneth Field Properties, and $0.8 million in increased labor costs.

Production and ad valorem taxes increased by 30% to $31.4 million during 2011, versus $24.2 million during 2010, mainly due to the increase in commodity pricing and production over 2010. Production and ad valorem taxes were 14% of total revenue in 2011 and 2010.

Depletion, depreciation, amortization and accretion expenses increased to $57.7 million during 2011, as compared to $47.0 million during 2010. The $10.6 million, or 23%, increase is principally due to a higher depletable base and increased production in 2011.

Pursuant to full cost accounting rules, we perform a ceiling test each quarter on our proved oil and gas assets. No provision for impairment was recorded in 2011 or 2010.

General and administrative expenses increased to $20.9 million during 2011, as compared to $19.4 million during 2010. The $1.5 million, or 8%, increase resulted from a $0.5 million increase in salaries and wages due to additional hiring to meet the demands of increased operations and $1.5 million of increased share-based compensation expense related to additional restricted stock grants awarded to employees in 2011. These increases were offset by decreased professional service fees, a significant portion of which were charges associated with the implementation of the provisions of the Sarbanes-Oxley act.

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Other Income (Expense). All oil and gas derivative instruments are accounted for under mark-to-market accounting rules, which provide for the fair value of the contracts to be reflected as either an asset or a liability on the balance sheet. The change in the fair value during an accounting period is reflected in the income statement for that period. During 2011, the realized and unrealized losses on our oil and gas derivatives totaled $5.3 million. This amount included approximately $20.8 million of realized losses, including $5.0 million of partial terminations of certain derivative contracts, offset by $15.5 million of increases in the unrealized fair value of oil and gas derivatives. During 2010, the realized and unrealized losses on oil and gas derivatives totaled $17.8 million and included approximately $9.6 million of unrealized losses in the fair value of oil and gas derivatives and $8.2 million of realized losses from monthly settlements.

Interest expense was $3.8 million during 2011, as compared to $4.9 million during 2010. The $1.1 million, or 21%, decrease is attributable to lower interest rates, a lower average debt balance and higher interest capitalization during 2011.

Income Tax Benefit (Expense). Income tax expense recognized during 2011 was $17.9 million, or 37.0% of income before income taxes, as compared to income tax expense of $2.4 million, or 27.9% of income before income taxes in 2010. The change in the effective rate reflects changes in permanent differences and revisions in 2010 to prior year estimates as a result of final income tax return filings. Income tax expense differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% due to state income taxes and estimated permanent differences. We expect income taxes to be between 36% and 39% of income (loss) before income taxes in future years. We carried a $13.7 million current deferred tax asset at December 31, 2011, for which no valuation allowance was recorded as it is more likely than not that the asset will be realized due to projected future taxable income.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash generated from operations, amounts available under our credit facility, proceeds from warrant exercises, proceeds from the issuance of Senior Notes and the sale of non-strategic oil and gas properties. For purposes of Management s Discussion and Analysis of Liquidity and Capital Resources, management has analyzed our cash flows and capital resources for the years ended December 31, 2012, 2011 and 2010.

	Year Ended December 31,		
	2012	2011	2010
		(in thousands)	
Cash provided by operating activities	$ 76,771	$ 101,087	$ 58,495
Cash provided used in investing activities	(447,447)	(217,006)	(69,123)
Cash provided by financing activities	370,475	115,210	12,017

Net cash provided by operating activities during 2012 was $76.8 million, as compared to $101.1 million during 2011 and $58.5 million during 2010. The decrease in net cash provided by operating activities from 2011 to 2012 was primarily due to changes in working capital and increased interest expense resulting from our 8.50% Senior Notes, partially offset by increased production. The increase in 2011 over 2010 was primarily due to higher commodity prices and production volumes and changes in working capital in 2011. We plan to reinvest a sufficient amount of our cash flow in our development operations in order to maintain our production over the long term, and plans to use external financing sources as well as cash flow from operations and cash reserves to increase our production.

Net cash used in investing activities was $447.4 million during 2012 as compared to $217.0 million during 2011 and $69.1 million during 2010. The primary investing activity in 2012 was cash used for capital expenditures of $498.8 million. Capital expenditures consisted of $248.0 million paid to acquire the New Permian Properties, $37.7 million paid for the Denbury Acquisition, $47.9 million in compression, facility and drilling projects in Aneth Field, $16.2 million in CO_2 acquisition, $82.3 million in drilling activities and infrastructure projects in the Permian Basin, $69.2 million in drilling and completion activities in the Bakken Properties and $12.6 million in recompletion and drilling activities in our Wyoming properties. A portion of these capital costs are accrued and not paid at period end. Capital divestitures include $49.5 million received from NNOGC for the sale of certain working interests in the Aneth Field Properties. The primary investing activity in 2011 was cash used for capital expenditures of $218.8 million, consisting of $169.2 million of acquisition, exploration and development expenditures and $49.6 million in purchases of proved oil and gas properties. The 2011 capital expenditures were comprised of $61.0 million in compression and facility related projects, $15.8 million in CO_2 acquisition, $74.5 million in acquisition and leasehold costs and $12.8 million in drilling activities in the Permian Basin, $46.0 million in drilling and completion activities in the Bakken Properties and $20.7 million in recompletion and drilling activities in our Wyoming properties. A portion of these capital costs are accrued and not paid at year end. The primary investing activity in 2010 was capital expenditures of $69.1 million. The 2010 capital expenditures were comprised of $30.8 million in leasehold and exploratory costs in North Dakota, $12.9 million in CO_2 acquisition and $21.6 million in other capital expenditures.

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Net cash provided by financing activities was $370.5 million in 2012 as compared to $115.2 million in 2011 and $12.0 million in 2010. The primary financing activities in 2012 were $401.9 million in proceeds received from the issuance of the Senior Notes, partially offset by $8.0 million in net payments under the Credit Facility and $10.0 million paid to retire a portion of our warrants. Primary financing activities in 2011 were $74.4 million in proceeds received from warrants exercised and $42.1 million in net borrowings under the Credit Facility. Primary financing activities in 2010 were $18.3 million in net borrowings under the Credit Facility and $4.0 million in deferred financing costs related to the amended credit agreement entered into on March 30, 2010. We are unable to predict the amount or timing of future warrant exercises.

If cash flow from operating activities does not meet expectations, we may reduce our expected level of capital expenditures and/or fund a portion of our capital expenditures using borrowings under our Credit Facility, issuances of debt and equity securities or from other sources, such as asset sales. We have in place an effective shelf registration pursuant to which an aggregate of $500 million of any such equity or debt securities could be issued. There can be no assurance that needed capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our Credit Facility or our Senior Notes. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain production or proved reserves. We believe that there remain several more years of drilling and development opportunity in the Bakken Properties, and that these opportunities have strong economic return potential. However, in light of the recent Permian Acquisitions, we believe it is prudent to consider monetizing our Bakken Properties. As a result, we have engaged the services of an advisor to explore this possibility.

We plan to continue our practice of hedging a significant portion of our production through the use of various derivative transactions. Our existing derivative transactions do not qualify as cash flow hedges, and we anticipate that future transactions will receive similar accounting treatment. Derivative settlements usually occur within five days of the end of the month. As is typical in the oil and gas industry, however, we do not generally receive the proceeds from the sale of our oil production until the 20th day of the month following the month of production. As a result, when commodity prices increase above the fixed price in the derivative contacts, we will be required to pay the derivative counterparty the difference between the fixed price in the derivative contract and the market price before receiving the proceeds from the sale of the hedged production. If this occurs, we may use working capital or borrowings under the Credit Facility to fund our operations.

Revolving Credit Facility

Our credit facility is with a syndicate of banks led by Wells Fargo Bank, National Association (the Credit Facility) with the Company as the borrower. The Credit Facility specifies a maximum borrowing base as determined by the lenders. The determination of the borrowing base takes into consideration the estimated value of our oil and gas properties in accordance with the lenders customary practices for oil and gas loans. The borrowing base is redetermined semi-annually, and the amount available for borrowing could be increased or decreased as a result of such redeterminations. Under certain circumstances, either the Company or the lenders may request an interim redetermination.

In April 2012, we entered into the Third Amendment to the amended and restated Credit Facility agreement which increased the size of the revolving Credit Facility from $500 million to $1 billion. In addition, under the terms of the amendment, at our option, the Credit Facility accrues interest at either (a) the London Interbank Offered Rate, plus a margin which varies from 1.50% to 2.50% or (b) the alternative Base Rate defined as the greater of (i) the Administrative Agent s Prime Rate (ii) the Federal Funds effective Rate plus 0.5% or (iii) an adjusted London Interbank Rate plus a margin which ranges from 0.50% to 1.50%. Each such margin is based on the level of utilization under the borrowing base. The Third Amendment also extended the maturity date of the revolving Credit Facility to April 2017. In connection with the Third Amendment, the semi-annual redetermination of the borrowing base was completed, confirming the borrowing base at $330 million. In December 2012, we entered into the Fifth Amendment to the amended and restated Credit Facility agreement which increased our Maximum Leverage Ratio for the fourth quarter of 2012. Additionally, we are currently in discussions with our bank syndicate to amend the Credit Facility in order to fund the purchase of the Option Properties.

As of December 31, 2012, outstanding borrowings were $162 million under the borrowing base of $330 million. The borrowing base availability had been reduced by $3.1 million in conjunction with letters of credit issued to vendors at December 31, 2012, and other limitations based upon a multiple of trailing Adjusted EBITDA as defined in the Credit Facility. To the extent that the borrowing base, as adjusted from time to time, exceeds the outstanding balance, no repayments of principal are required prior to maturity. The Credit Facility is guaranteed by all of our subsidiaries and is collateralized by substantially all of the proved oil and gas assets of Resolute Aneth, LLC and Resolute Wyoming, Inc., which are wholly-owned subsidiaries of the Company.

As of December 31, 2012, the weighted average interest rate on the outstanding balance under the Credit Facility was 2.99%. The recorded value of the Credit Facility approximates its fair market value because the interest rate of the Credit Facility is variable over the term of the loan (See Note 5 to the Consolidated Financial Statements).

The Credit Facility includes terms and covenants that place limitations on certain types of activities, the payment of dividends, and require satisfaction of certain financial tests. We were in compliance with all terms and covenants of the Credit Facility at December 31, 2012.

Resolute Energy Corporation, the stand-alone parent entity, has insignificant independent assets and no operations. There are no restrictions on our ability to obtain cash dividends or other distributions of funds from our subsidiaries, except those imposed by applicable law.

Senior Notes

In April 2012, we consummated a private placement of senior notes with a principal amount of $250 million, and a follow on issuance of senior notes with a principal amount of $150 million (the Senior Notes). The Senior Notes are due May 1, 2020, and bear an annual interest rate of 8.50% with the interest on the notes is payable semiannually in cash on May and November 1 of each year, beginning November 1, 2012. We used the $250 million of proceeds from the May 2012 issuance to repay outstanding borrowings under the Credit Facility, with the remainder reserved for general corporate purposes, including capital expenditures. We used the $150 million of proceeds from the December 2012 issuance to partially finance the Permian Acquisitions.

The Senior Notes were issued under an Indenture (the Indenture) among the Company, our existing subsidiaries (the Guarantors) and U.S. Bank National Association, as trustee (the Trustee) in a private transaction not subject to the registration requirements of the Securities Act of 1933. The Indenture contains affirmative and negative covenants that, among other things, limit our and the Guarantors ability to make investments, incur additional indebtedness or issue preferred stock, create liens, sell assets, enter into agreements that restrict dividends or other payments by restricted subsidiaries, consolidate, merge or transfer all or substantially all of our assets, engage in transactions with our affiliates, pay dividends or make other distributions on capital stock or prepay subordinated indebtedness and create unrestricted subsidiaries. The Indenture also contains customary events of default. Upon occurrence of events of default arising from certain events of bankruptcy or insolvency, the Senior Notes shall become due and payable immediately without any declaration or other act of the Trustee or the holders of the Senior Notes. Upon the occurrence of certain other events of default, the Trustee or the holders of the Senior Notes may declare all outstanding Senior Notes to be due and payable immediately. We were in compliance with all financial covenants under our Senior Notes as of December 31, 2012.

The Senior Notes are general unsecured senior obligations of the Company and guaranteed on a senior unsecured basis by the Guarantors. The Senior notes rank equally in right of payment with all existing and future senior indebtedness of the Company, will be subordinated in right of payment to all existing and future senior secured indebtedness of the Guarantors, will rank senior in right of payment to any future subordinated indebtedness of the Company and will be fully and unconditionally guaranteed by the Guarantors on a senior basis.

The Senior Notes are redeemable by us on or after May 1, 2016, on not less than 30 or more than 60 days prior notice, at redemption prices set forth in the Indenture. In addition, at any time prior to May 1, 2015, we may use the net proceeds from equity offerings and warrant exercises to redeem up to 35% of the principal amount of notes issued under the Indenture at a redemption price equal to 108.50% of the principal amount of the notes redeemed, plus accrued and unpaid interest. The Senior Notes may also be redeemed at any time prior to May 1, 2016, at the option of the Company at a redemption price equal to 100% of the principal amount of the notes redeemed plus the applicable premium, and accrued and unpaid interest and additional interest, if any, to the applicable redemption date as set forth in the Indenture. If a change of control occurs, each holder of the Notes will have the right to require that we purchase all of such holder s Notes in an amount equal to 101% of the principal of such Notes, plus accrued and unpaid interest, if any, to the date of the purchase.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet financing arrangements other than operating leases and have not guaranteed any debt or commitments of other entities or entered into any options on non-financial assets.

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Contractual Obligations

We had the following contractual obligations and commitments for the next five years as of December 31, 2012:

	Less than 1 year	1-3 Years	3 5 Years (in thousands)	More Than 5 Years	Total (6)
Obligations:					
Senior Notes and related interest	$ 34,000	$ 68,000	$ 68,000	$ 485,000	$ 655,000
Credit facility [1]			162,000		162,000
Office and equipment leases	770	735	274		1,779
Operating equipment leases [2]	2,635	4,855	3,126	245	10,861
Vehicle leases	750	689	13		1,452
Derivative premiums	4,319	4,995			9,314
ExxonMobil escrow agreement [3]	1,700	3,400	2,400	12,900	20,400
Construction purchase obligations [4]	320				320
CO_2 purchases [5]	28,739	57,478	11,432		97,649
Total	$ 73,233	$ 140,152	$ 247,245	$ 498,145	$ 958,775

1) Represents the outstanding principal amount under our Credit Facility. This table does not include future commitment fees, interest expense or other fees because the Credit Facility is a floating rate instrument, and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.
2) Operating equipment leases consist of compressors and other oil and gas field equipment used in the CO_2 project.
3) Under the terms of our purchase agreement with ExxonMobil, we are obligated to make annual deposits into an escrow account that will be used to fund plugging and abandonment liabilities associated with the ExxonMobil Properties.
4) Represents purchase commitments in effect at December 31, 2012, related to construction projects in the Aneth Field Properties.
5) Represents the minimum take-or-pay quantities associated with our existing CO_2 purchase contracts. For purposes of calculating the future purchase obligation under these contracts, we have assumed the purchase price over the term of the contract was the price in effect as of December 31, 2012.
6) Total contractually obligated payment commitments do not include the anticipated settlement of derivative contracts, obligations to taxing authorities or amounts relating to our asset retirement obligations, which include plugging and abandonment obligations, due to the uncertainty surrounding the ultimate settlement amounts and timing of these obligations.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses and related disclosure of contingent assets and liabilities. The application of accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate estimates and assumptions on a regular basis. We base estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ, perhaps materially, from these estimates and assumptions used in the preparation of our financial statements. Provided below is an expanded discussion of our most significant accounting policies, estimates and judgments used in the preparation of the financial statements.

Oil and Gas Properties. We use the full cost method of accounting for oil and gas producing activities. All costs incurred in the acquisition, exploration and development of properties, including costs of unsuccessful exploration, costs of surrendered and abandoned leaseholds, delay lease rentals and the fair value of estimated future costs of site restoration, dismantlement and abandonment activities, improved recovery systems and a portion of general and administrative and operating expenses are capitalized on a country wide basis (the Cost Center).

We conduct tertiary recovery projects on a portion of our oil and gas properties in order to recover additional hydrocarbons that are not recoverable from primary or secondary recovery methods. Under the full cost method, all development costs are capitalized at the time incurred. Development costs include charges associated with access to and preparation of well locations, drilling and equipping development wells, test wells, and service wells including injection wells; acquiring, constructing, and installing production facilities and providing for improved recovery systems. Improved recovery systems include all related facility development costs and the cost of the acquisition of tertiary injectants, primarily purchased CO_2. The development cost related to CO_2 purchases are incurred solely for the purpose of gaining access to incremental reserves not otherwise recoverable. The accumulation of injected CO_2, in combination with additional purchased and recycled CO_2, provide future economic value over the life of the project.

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In contrast, other costs related to the daily operation of the improved recovery systems are considered production costs and are expensed as incurred. These costs include, but are not limited to, costs incurred to maintain reservoir pressure, compression, electricity, separation, and re-injection of recovered CO_2 and water.

Capitalized general and administrative and operating costs include salaries, employee benefits, costs of consulting services and other specifically identifiable capital costs and do not include costs related to production operations, general corporate overhead or similar activities.

Investments in unproved properties are not depleted, pending determination of the existence of proved reserves. Unproved properties are periodically evaluated for impairment. Unproved properties whose costs are individually significant are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. Properties are grouped for purposes of assessing impairment when it is not practicable to assess the amount of impairment of properties on an individual basis. The amount of impairment assessed is added to the costs to be amortized, or is reported as a period expense as appropriate.

Pursuant to full cost accounting rules, we must perform a ceiling test each quarter on our proved oil and gas assets. The ceiling test provides that capitalized costs less related accumulated depletion and deferred income taxes for each Cost Center may not exceed the sum of (1) the present value of future net revenue from estimated production of proved oil and gas reserves using current prices, excluding the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, and a discount factor of 10%; plus (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) income tax effects related to differences in the book and tax basis of oil and gas properties. Should the net capitalized costs for a Cost Center exceed the sum of the components noted above, an impairment charge would be recognized to the extent of the excess capitalized costs.

No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and the gain significantly alters the relationship between capitalized costs and proved oil reserves of the Cost Center.

Depletion and amortization of oil and gas properties is computed on the unit-of-production method based on proved reserves. Amortizable costs include estimates of asset retirement obligations and future development costs of proved reserves, including, but not limited to, costs to drill and equip development wells, constructing and installing production and processing facilities, and improved recovery systems including the cost of required future CO_2 purchases.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Reserves and their relation to estimated future net cash flows affect our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserves estimates. We prepare reserves estimates, and the projected cash flows derived from these reserves estimates, in accordance with SEC and FASB guidelines. The accuracy of our reserves estimates is a function of many factors including but not limited to the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates. Our proved reserves estimates are a function of many assumptions, any or all of which could deviate significantly from actual results. As such, reserves estimates may vary materially from the ultimate quantities of oil, gas and NGL eventually recovered.

Derivative Instruments. We enter into derivative contracts to manage our exposure to oil and gas price volatility and these contracts may take the form of swaps, puts, calls, collars and other such arrangements. Derivative instruments are recognized on the balance sheet as either assets or liabilities measured at fair value. We have not elected to apply cash flow hedge accounting, and consequently, recognize gains and losses in earnings rather than deferring such amounts in other comprehensive income as allowed under cash flow hedge accounting. Realized gains and losses on derivative instruments are recognized in the period in which the related contract is settled. Both the realized and unrealized gains and losses on derivative instruments are reflected in other income (expense) in the consolidated statements of income. Cash flows from derivatives are reported as cash flows from operating activities.

Asset Retirement Obligations. Asset retirement obligations relate to future costs associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred (typically when the asset is installed at the production location), and the cost of such liability increases the carrying amount of the related long-lived asset by the same amount. The liability is accreted each period and the capitalized cost is depleted on a units-of-production basis as part of the full cost pool. Revisions to estimated retirement obligations result in adjustments to the related capitalized asset and corresponding liability.

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Our estimated asset retirement obligation liability is based on estimated economic lives, estimates as to the cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

Business Combinations. We account for all business combinations using the acquisition method which involves the use of significant judgment. Under the acquisition method of accounting, a business combination is accounted for based on the fair value of the consideration given. The assets and liabilities acquired are measured at fair value and the purchase price is allocated to the assets and liabilities based on these fair values. The excess of the cost of an acquisition, if any, over the fair value of the assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquisition, if any, is recognized immediately in earnings as a gain. Determining the fair values of the assets and liabilities acquired involves the use of judgment since fair values are not always readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities and the present value of estimated future cash flows, among others.

Share-Based Compensation. Share-based compensation expense is measured at the estimated grant date fair value of the awards and is amortized over the requisite service period (usually the vesting period). We estimate forfeitures in calculating the cost related to share-based compensation as opposed to recognizing these forfeitures and the corresponding reduction in expense as they occur.

Revenue Recognition. Oil and gas revenue is recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred and the collectability of the revenue is probable. Oil and gas revenue is recorded using the sales method.

Income taxes. Deferred tax assets and liabilities are recorded to account for the expected future tax consequences of events that have been recognized in the financial statements and tax returns. The ability to realize the deferred tax assets is routinely assessed. If the conclusion is that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance. The future taxable income is considered when making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and gas prices). Income tax positions are also required to meet a more-likely-than-not recognition threshold to be recognized in the financial statements. Tax positions that previously failed to meet the more-likely-than-not threshold are recognized in the first subsequent financial reporting period in which that threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not threshold are derecognized in the first subsequent financial reporting period in which that threshold is no longer met.

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ITEM 7A. QUANTITIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
Commodity Price Risk and Derivative Arrangements

Our major market risk exposure is in the pricing applicable to oil and gas production. Realized pricing on our unhedged volumes of production is primarily driven by the spot market prices applicable to oil production and the prevailing price for gas. Oil and gas prices have been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for unhedged production depend on many factors outside of our control.

We employ derivative instruments such as swaps, puts, calls, collars and other such agreements. The purpose of these instruments is to manage our exposure to commodity price risk in order to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices.

Under the terms of our credit agreement the form of derivative instruments to be entered into is at our discretion, not to exceed (i) 85% of our anticipated production from proved properties in the next two years and (ii) the greater of 75% of our anticipated production from proved properties or 85% of our anticipated production from proved developed producing properties utilizing economic parameters specified in our credit agreement, including escalated prices and costs.

By removing the price volatility from a significant portion of our oil and gas production, we have mitigated, but not eliminated, the potential effects of volatile prices on cash flow from operations for the periods hedged. While mitigating negative effects of falling commodity prices, certain of these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers.

The following table represents our two-way commodity collar contracts as of December 31, 2012.

		(NYMEX WTI $/Bbl)	
Year	**Bbl per Day**	**Weighted Average Floor Price**	**Weighted Average Ceiling Price**
2013	775	$ 80.00	$ 105.00
2014	1,500	$ 65.00	$ 110.00

The following table represents our three-way commodity collar contracts as of December 31, 2012.

			(NYMEX WTI $/Bbl)	
Year	**Bbl Per Day**	**Weighted Average Short Put Price**	**Weighted Average Floor Price**	**Weighted Average Ceiling Price**
2014	2,000	$ 70.00	$ 85.00	$ 100.83

The following table represents our commodity call option contracts as of December 31, 2012.