Resolute Energy Corp
Form 10-K
March 05, 2015

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, 2014

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 (State or other jurisdiction of incorporation or organization)	27-0659371 (I.R.S. Employer Identification Number)
1700 Lincoln, Suite 2800	
Denver, CO (Address of principal executive offices)	80203 (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

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 disclosure of 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, 2014, computed by reference to the price at which the common stock was last sold as posted on the New York Stock Exchange, was $463.6 million.

As of February 27, 2015, 77,612,287 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 2015 annual meeting of stockholders ("Proxy Statement") are incorporated by reference into Part III of this Form 10-K.

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 expressions are intended to identify such statements. Forward-looki statements included in this report relate to, among other things, regarding our production and cost guidance for 2015; anticipated capital expenditures in 2015 and the sources of such funding; our financial condition and management of the Company in the current commodity price environment; future financial and operating results; our intention to evaluate and pursue de-levering transactions, including joint ventures and non-core asset sales; liquidity and availability of capital including projections of free cash flow; future borrowing base adjustments and the effect thereof; future production, reserve growth and decline rates; production rates, decline rates and estimated ultimate recoveries of oil and gas; our plans and expectations regarding our development activities including drilling, deepening, recompleting, fracing and refracing wells, the number of such potential projects, locations and productive intervals, and the resource potential of such projects; and the prospectivity of our properties and acreage. 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 and liquidity and the discovery, estimation and development of, and our ability to replace oil and gas reserves;

a lack of available capital and financing, including the capital needed to pursue our production and other plans for our properties, on acceptable terms, including as a result of a reduction in the borrowing base under our revolving credit facility;

risks related to our level of indebtedness;

our ability to fulfill our obligations under our revolving credit facility, secured term loan facility, the senior notes and any additional indebtedness we may incur;

constraints imposed on our business and operations by our revolving credit facility, senior notes and secured debt may limit our ability to execute our business strategy;

our future cash flow, liquidity and financial position;

the success of our business and financial strategy, derivative strategies and plans;

risks associated with all of our Aneth Field oil production being purchased by a single customer and connected to such customer with a pipeline that we do not own or control;

inaccuracies in reserve estimates;

future write downs of the carrying value of our oil and gas properties;

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

the amount, nature and timing of our capital expenditures, including future development costs;

anticipated CO_2 supply, which is currently sourced exclusively from Kinder Morgan CO_2 Company, L.P.;

the effectiveness and results of our CO_2 flood program at Aneth Field;

our relationship with the Navajo Nation, the local community in the area where we operate Aneth Field, and Navajo Nation Oil and Gas Company, as well as certain purchase rights held by Navajo Nation Oil and Gas Company;

the impact of any U.S. or global economic recession;

the success of the development plan for and production from our oil and gas properties;

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

the completion, timing and success of drilling on our properties;

availability of, or delays related to, drilling, completion and production, personnel, supplies and equipment;
risks and uncertainties in the application of available horizontal drilling and completion techniques;
uncertainty surrounding occurrence and timing of identifying drilling locations and necessary capital to drill such locations;

our ability to fund and develop our estimated proved undeveloped reserves;
the effect of third party activities on our oil and gas operations, including our dependence on gas gathering and processing systems;
our operating costs and other expenses;
our success in marketing oil and gas;
the impact and costs related to compliance with, or changes in, laws or regulations governing our oil and gas operations, including changes in Navajo Nation laws, and the potential for increased regulation of drilling and completion techniques, underground injection or fracing operations;
our relationships with the local communities in the areas where we operate;
the availability of water and our ability to adequately treat and dispose of water after drilling and completing wells;
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;
our ability to achieve the growth and benefits we expect from our acquisitions;
risks associated with unanticipated liabilities assumed, or title, environmental or other problems resulting from, our acquisitions;
the concentration of our producing properties in a limited number of geographic areas;
the success of our derivatives program;
potential changes to regulations affecting derivatives instruments;
environmental liabilities under existing or future laws and regulations;
the impact of weather and the occurrence of disasters, such as fires, explosions, floods and other events and natural disasters;
competition in the oil and gas industry;
developments in oil and gas producing countries;
loss of senior management or key technical personnel;
timing of issuance of permits and rights of way, including the effects of any government shut-downs;
potential delays in the upgrade of third-party electrical infrastructure serving Aneth Field and potential power supply limitations;
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;
losses possible from pending or future litigation;
risks related to our common stock including potential delisting from the NYSE, complication of “penny stock” rules and potential declines in our stock prices and dilution to stockholders;
risk factors discussed or referenced in this report; and
other factors, many of which are beyond our control.

Additionally, the Securities and Exchange Commission (“SEC”) requires oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, under existing economic conditions, operating methods, and governmental regulations. The SEC permits the optional disclosure of probable and possible reserves. From time to time, we may elect to disclose “probable” reserves and “possible” reserves, excluding their valuation, in our SEC filings, press releases and investor presentations. The SEC defines “probable” reserves as “those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are likely as not to be recovered.” The SEC defines “possible” reserves as “those additional reserves that are less certain to be recovered than probable reserves.” The Company applies these definitions when estimating probable and possible reserves. Statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any reserves estimates or potential resources disclosed in our public filings, press releases and investor presentations that are not specifically designated as being estimates of proved reserves may include estimated reserves not necessarily calculated in accordance with, or contemplated by the SEC’s reserves reporting guidelines.

The SEC's rules prohibit us from including resource estimates in our public filings with SEC. Our potential resource estimates include estimates of hydrocarbon quantities for (i) new areas for which we do not have sufficient information to date to classify as proved, probable or possible reserves, (ii) other areas to take into account the level of certainty of recovery of the resources and (iii) uneconomic proved, probable or possible reserves. Potential resource estimates do not take into account the certainty of resource recovery and are therefore not indicative of the expected future recovery and should not be relied upon for such purpose. Potential resources might never be recovered and are contingent on exploration success, technical improvements in drilling access, commerciality and other factors. In our press releases and investor presentations, we sometimes include estimates of quantities of oil and gas using certain terms, such as "resource," "resource potential," "EUR," "oil in place," or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC definition of proved, probable and possible reserves. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by Resolute. The Company believes its potential resource estimates are reasonable, but such estimates have not been reviewed by independent engineers. Furthermore, estimates of potential resources may change significantly as development provides additional data, and actual quantities that are ultimately recovered may differ substantially from prior estimates.

Finally, 24 hour peak IP rates and 30 day peak IP rates for both our wells and for those wells that are located near to our properties are limited data points in each well's productive history and not necessarily indicative or predictive of future production rates, EUR or economic rates of return from such wells and should not be relied upon for such purpose.

You are urged to consider closely the disclosure in this Annual Report on Form 10-K, in particular the factors described under "Risk Factors."

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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 Financ Data") for all periods prior to September 25, 2009, and Resolute Energy Corporation and its subsidiaries for all periods thereafter.

Business Overview

Resolute Energy Corporation, a Delaware corporation incorporated on July 28, 2009, is 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 primarily 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" or "Permian Basin Properties"), and the Powder River and Big Horn Basins in Wyoming (the "Wyoming Properties"). Our primary operational focus for 2015 is on maintaining production while reducing operating costs in the current depressed commodity price environment. Over the longer term, we will focus on increasing reserves and production from these properties while improving efficiency and optimizing operating costs. We plan to expand our reserve base and production 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 Wyoming Properties, through carefully targeted exploration activities in our properties and through opportunistic acquisitions.

During 2014 oil sales comprised approximately 89% of revenue, and our December 31, 2014, estimated net proved reserves were approximately 74.2 million barrels of oil equivalent ("MMBoe"), of which approximately 56% and 45% were proved developed reserves and proved developed producing reserves ("PDP"), respectively. Approximately 86% of our estimated net proved reserves were oil and approximately 92% were oil and natural gas liquids ("NGL"). The December 31, 2014, pre-tax present value discounted at 10% ("PV-10") of our net proved reserves was $973 million and the standardized measure of our estimated net proved reserves was $833 million. For additional information about the calculation of our PV-10 and standardized measure, please read "Business and Properties — Estimated Net Proved Reserves."

In view of the current depressed oil and gas price environment, we have adopted an operating and financial plan for 2015 that holds production essentially flat, while preserving capital and paying down debt. We expect to fund our 2015 capital expenditures exclusively from internally generated cash flow. We also continue to explore alternative means to increase activity within our asset base including ongoing evaluation of opportunities in light of the commodity price environment and the evolving drilling, completion and operating cost structure. We also may enter into joint ventures to drill wells on the Company's acreage.

Business Strategies

Our business strategies in the near term during the current period of depressed oil and gas prices are focused on maintaining production while reducing operating costs and leverage. Planned capital expenditures during 2015 remain within future anticipated cash flow. Outstanding indebtedness at December 31, 2014, consisted of $235 million in Credit Facility debt, $150 million under the Secured Term Loan Facility and $400 million of senior notes. As of December 31, 2014, our Credit Facility had a borrowing base of $330 million. We expect that this borrowing base will be reduced, perhaps significantly, at the next borrowing base redetermination, which is expected to occur on or about March 31, 2015. We will pursue such actions as are necessary to preserve our liquidity and to remain in compliance with the terms and conditions of our credit facility (the “Revolving Credit Facility”), secured term loan facility (the “Secured Term Loan Facility”) and 8.5% senior notes (the “Senior Notes”), including additional second lien borrowings, non-core asset sales, sales of other debt or equity securities, and other transactions. Our management team has significant experience in managing intensive oil and gas operations through commodity price cycles. As the operator of our Aneth Field Properties, Wyoming Properties and the substantial majority of the Permian Properties, we have the ability to more directly manage our costs, control the timing of our exploitation, drilling and producing activities and implement programs to maintain production and improve operational efficiency. In 2015 we will also continue to explore other ways to de-lever our balance sheet, including pursuing non-core asset sales and considering joint ventures to drill wells on the Company’s acreage.

Upon returning to a normalized commodity price environment, our business strategies would return to strategies substantially similar to those that we have pursued over the last several years, which include creating value for our shareholders 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 this medium to long term strategy 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. These activities include the McElmo Creek Unit IIC subzone of the Desert Creek formation (the “DC IIC”) CO_2 expansion, increasing the processing of CO_2 in existing patterns, drilling in various areas of the field and bringing new reserves into the proved category by expanding the CO_2 flood into the Ratherford Unit. For all of the Aneth Field Properties, proved developed non-producing ("PDNP") and proved undeveloped reserves ("PUD") at year end constitute 13% and 43%, respectively, of the proved reserves. These reserves primarily relate to the CO_2 flood that we commenced in 2006, which followed a successful CO_2 flood program in the McElmo Creek Unit implemented in 1985 by a prior operator. Using a phased approach, we have been expanding this CO_2 flood within the field with demonstrable success.

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 two of the most active oil-focused resource plays in the United States. Our horizontal drilling program has been focused in the Wolfcamp, Spraberry and Bone Spring plays in the Permian Basin and the Turner formation in the Powder River Basin in Wyoming. Both of these areas are characterized by relatively low risk drilling, with production heavily weighted toward oil and NGL. We do not anticipate additional horizontal drilling in 2015 in the current depressed oil price environment, however, upon recommencing drilling, we will focus 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.

We also may develop additional opportunities to exploit existing acreage positions by engaging in focused exploration activities. For example, we control acreage in the Powder River Basin of Wyoming which contains emerging exploration plays. There, we own leases covering approximately 47,400 net acres which produce from the Muddy formation. These leases also hold the shallower formations such as the Parkman, Sussex, Shannon, Niobrara, Turner and Mowry. Underlying these leases, we believe that we have identified several deeper Minnelusa prospects. In the Big Horn Basin, we own leases covering approximately 34,700 net acres in which our primary target is the Frontier and Phosphoria formations and the Mowry oil shale.

In the Permian Basin, offset operators are continuing to derisk additional zones within both the Wolfcamp shale and the Bone Spring formation in the Delaware Basin and in the Wolfcamp and Spraberry formations in the Midland Basin. These zones have the potential to significantly expand our current drilling inventory which is focused on the upper Wolfcamp zones.

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 and the majority of the Permian Properties, we have the ability to more 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.

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 with significant development potential. In December 2012 and March 2013 we acquired properties in the Permian Basin that we refer to as the "Permian Acquisitions." 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. The original component of our Permian Properties was acquired in 2011. We expect to evaluate opportunities from time to time to acquire properties that are prospective for production of oil and NGL, particularly in the Permian and Powder River basins. 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 issue debt or equity securities and incur additional indebtedness.

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our 2015 and longer term business strategies, including:

A High Quality Base of Long-Lived Oil Producing Properties. As of December 31, 2014, we had estimated net proved reserves of approximately 74.2 MMBoe, of which approximately 86% were oil and approximately 92% were oil and NGL. Based on our 2014 year-end reserve report, our total proved reserve to production ratio was sixteen years. The shallow decline rate and long lives of our legacy producing properties result in a slower reserve depletion rate and reduced reinvestment requirements relative to other producing areas in the United States.

Operating Control Over Our Properties. As operator, we have the ability to more directly control the timing, scope and costs of most development projects undertaken on our various properties. We operate our Aneth Field, Wyoming Properties and the substantial majority of our Permian Properties, which constitute approximately 98% of our proved reserves. Further, operatorship of our Aneth Field, Permian Basin Properties and Wyoming Properties (excluding our Big Horn Basin Properties) is secured for the foreseeable future, as approximately 89% of the acreage is held by production.

Favorable Commodity Price Hedges in Place for 2015 and 2016. The Company's hedging program covers approximately 74 percent of forecast 2015 oil production, or 6,600 barrels per day, at a weighted average floor price of $86.40 per barrel. Approximately 41 percent of anticipated 2015 gas production is covered by swaps with an average strike of $3.64 and a three-way collar with short put price of $3.75, a floor of $4.50 and a ceiling of $5.55 per million British thermal units ("MMBtu"). We also have hedged 6,500 barrels of oil per day for 2016, at a weighted average price of $80.42.

Assets Generate Strong Free Cash Flow. We anticipate that each of our major properties, Aneth Field in Utah, the Permian Properties in Texas and New Mexico, and Hilight Field in Wyoming, will generate sufficient free cash flow to fund their 2015 capital 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 two of the most active oil resource plays in the United States. We believe that this portfolio provides an attractive drilling inventory.

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 worked together previously 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 operated primarily in the Denver-Julesburg Basin in northeast Colorado. HS Resources, Inc. was acquired by Kerr-McGee Corporation in 2001 for $1.8 billion. We also employ more than fifty oil and gas technical professionals, including geologists, petroleum engineers, and land and financial specialists, who have an average of approximately twenty 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, 2014, reserve report, which were prepared by Resolute and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers.

	Estimated Net Proved Reserves at December 31, 2014 (MMBoe)				
	Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved	2014 Net Daily Production (Boe per day)
Aneth Field Properties	23.9	6.8	23.5	54.2	6,287
Permian Properties	5.9	0.1	8.1	14.1	4,656
Wyoming Properties	3.9	0.8	1.2	5.9	1,770
Bakken Properties	—	—	—	—	14
Total	33.7	7.7	32.8	74.2	12,727
Future operating costs ($ millions)				$2,018.8	
Future production taxes ($ millions)				694.9	
Future capital costs ($ millions)				1,008.4	
Future operating costs ($/Boe)				$27.21	
Future production taxes ($/Boe)				9.37	
Future capital costs ($/Boe)				24.90	

Description of Properties

Aneth Field Properties

Aneth Field, a giant legacy oil field in southeast Utah, holds 73% of our net proved reserves as of December 31, 2014, and accounted for 49% of our production during 2014, averaging 6,287 equivalent barrels of oil ("Boe") per day, of which 98% was oil. 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 62%, 67.5% and 59%, respectively, at December 31, 2014. We had interests in and operated 388 gross (246 net) producing wells and 333 gross (210 net) active water and CO_2 injection wells.

Aneth Field was discovered in 1956 by Texaco and has produced 440 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 the three separate operating units. In 1985, Mobil Oil Corporation (now "ExxonMobil"), 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 has been accomplished generally with well-tested methodologies, including drilling and infilling vertical wells, horizontal drilling, waterflood activities and CO_2 flooding.

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, 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 83 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 181% from 2006. In 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, 2014, we were injecting CO_2 in approximately eighteen out of a total of 54 injection wells. Nine producing wells in Phase 4 are experiencing incremental oil production response, and production in this area of the CO_2 flood has increased by 20% from 2010. During 2015 CO_2 injection will continue into the currently developed patterns of Phase 1, 2, 3 and 4.

The CO_2 flood expansions within the Aneth Unit and the projected CO_2 flood in the Ratherford Unit 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 PUDs. Following installation of the necessary infrastructure, these CO_2-related reserves are reclassified as PDNP. Once a response is exhibited at a producing well, the tertiary reserves associated with that well are then reclassified to PDP. Within Aneth Field at December 31, 2014, we had estimated net proved reserves of 30.3 MMBoe that were classified as PDNP or PUD. Of these reserves, 27.6 MMBoe are attributable to recoveries associated with expansions, extensions and processing of the tertiary recovery CO_2 floods.

We believe significant opportunity exists to increase production from existing proved reserves. For example, we anticipate production growth from the DC IIC in the McElmo Creek Unit. We began recompleting the DC IIC 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 directly CO_2 flooded. We have reactivated the DC IIC as a waterflood with highly economic results and plan to implement a CO_2 flood in this zone. Within the Ratherford Unit, we have two CO_2 flood projects, one targeting both the Desert Creek I and II zones and a second targeting primarily the Desert Creek I zone.

Beyond those projects included in our proved reserves, we believe that there are opportunities to increase reserves and production in Aneth Field through infill drilling, projects designed to increase processing rates within the CO_2 floods and through technological improvements that may allow for greater recovery efficiency across the field.

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 own a 68% interest. 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. At December 31, 2014, we did not have any take-or-pay liability. We do not have the right to resell CO_2 required to be purchased under the Kinder Morgan contract.

Oil production from our Aneth Field is characterized as a light, sweet crude oil with an API gravity of 40 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., a subsidiary of Western Refining Inc. ("Western"). Western currently purchases all of the oil production from Aneth Field under a purchase agreement dated July 2014. On December 31, 2014, the Company entered into an amendment to the purchase agreement with Western, which provides for Resolute to receive a price equal to the NYMEX oil price minus a differential of $8.00 per barrel of oil. The amendment also provides that the term of the purchase agreement shall continue automatically after December 31, 2014, until

March 31, 2015, and thereafter on a month-to-month basis until terminated by a party with ninety days prior notice. If, for any reason, Western is unable to process our oil, there is alternative access to markets through rail and truck facilities or, in early 2015, through the FERC-regulated Texas-New Mexico pipeline owned by Western.

Capital expenditures at Aneth Field during 2014 were approximately $33.1 million, representing approximately twenty percent of our total capital expenditures during the year. Although the expansion of the CO_2 flood will require significant investments for infrastructure, wellhead equipment and CO_2 purchases, we expect that, in the aggregate, Aneth Field will generate sufficient cash flow to fund these requirements.

During the second quarter of 2012, we entered into two transactions regarding the Aneth Field Properties through which we and NNOGC consolidated our respective 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. The first transfer took place in July 2012 and the second transfer took place in January 2013.

The Cooperative Agreement amendment also cancelled 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 2012 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 following table presents, as of December 31, 2014, 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 all three of the units of our Aneth Field Properties through 2043. 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, 2014, reserve report.

	Estimated Future Capital Expenditures (excluding CO_2)	Proved Reserves (MMBoe)	Estimated Future Development Cost ($/Boe, excluding CO_2)	Estimated Future CO_2 Purchases
	(in millions, except as otherwise indicated)			
Aneth Unit -- Phase 1, 2, 3 and 4 (PDNP)	$—	4.9	$ -	$ 56.1
Aneth Unit -- Phase 4A-H (PUD)	57.9	7.6	7.63	113.5
Aneth Unit -- Pilot Area (PUD)	24.3	1.3	18.42	19.6
McElmo Creek Unit -- DC IIC (PDNP portion)	17.1	1.6	10.34	21.5
McElmo Creek Unit -- DC IIC (PUD portion)	42.0	3.0	14.19	26.0
Ratherford Unit -- DC IA (PUD)	39.2	4.9	7.92	60.0
Ratherford Unit -- DC IIC (PUD)	72.2	4.3	16.71	28.0
Total	$252.7	27.6	$ 9.14	$ 324.7

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 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 continue to 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 are exploring options to expand the plant to separate CO_2 and hydrocarbon gas as well. If economically feasible, the hydrocarbon gas would be sold, adding income streams to the field economics while the separated CO_2 stream would be reinjected into the producing zone. The plant hydrocarbon extraction expansion has been through early stages of engineering design and is currently on hold pending recovery of NGL prices.

The saleable gas stream is transported fifty miles to a gas processing plant in Lisbon, Utah, operated by CCI LLC. We are paid on a percent of proceed basis that averaged $4.76 per Mcf during 2014. We are undertaking discussions with CCI that would allow us to sell additional volumes of this partially contaminated gas.

Permian Properties

As of December 31, 2014, we had interests in 36,500 gross (25,000 net) acres in the Permian Basin of Texas and southeast New Mexico. Our position is divided between three principal project areas: the Delaware Basin project area in Reeves County, the Midland Basin project area 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. Approximately 14.1 MMBoe of proved reserves are associated with these assets as of December 31, 2014. During the year, we completed 15 gross (7.9 net) wells in the Permian Properties and had 234 gross (197 net) producing wells at year-end 2014. As of December 31, 2014, we were in the process of drilling 1 gross (0.7 net) well and had 2 gross (1.2 net) wells awaiting completion operations. During 2014, average net daily production from the Permian Properties was 4,656 Boe and was 80% liquids. See “Business and Properties – Marketing and Customers” for more information on how production from this area is sold. In January and February 2015 we successfully completed the three horizontal wells that were in the process of drilling or awaiting completion operations at year end.

Delaware Basin Project. The Delaware Basin project area includes approximately 21,200 gross (13,200 net) acres. The primary objective in this area is the Wolfcamp formation. Within the Wolfcamp formation, we have targeted primarily the Wolfcamp A and B subzones. Within our project area, other operators are also developing the Wolfcamp C and D subzones as well as the third Bone Spring formation. Based on drilling activity to date, approximately 40% of the acreage is held by production. Approximately 5.4 MMBoe of proved reserves are associated with these assets as of December 31, 2014. We believe that growth potential exists from more than 280 gross prospective wells targeting three zones in the Wolfcamp formation based on 160-acre spacing. Significant additional opportunity exists from reduced spacing as well as additional subzones.

Midland Basin Project. The Midland Basin project area includes approximately 10,000 gross (7,800 net) acres. We acquired our interests in this area in transactions over 2011, 2012 and 2013. In the 2011 transaction, we acquired approximately 4.0 MMBoe and 750 gross and net acres. The 2012 and 2013 acquisitions included 12.9 MMBoe of proved reserves and 8,286 gross (6,053 net) acres. Approximately 7.2 MMBoe of proved reserves are associated with these assets as of December 31, 2014. We believe that growth potential exists from more than 180 gross prospective horizontal wells targeting multiple zones in the Wolfcamp and Spraberry formations. Within this inventory, 114 wells are located in our core operated Gardendale area in Midland and Ector counties based on 80- to 120-acre spacing and three zones. Our acreage in this area is held by production. In Gardendale we have primarily targeted the Wolfcamp B subzone. Other operators in the area are actively developing the lower and middle Spraberry as well as the Wolfcamp A and C subzones.

Northwest Shelf Project. In 2012 we acquired assets in Lea County, New Mexico, in Denton, Gladiola and South 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 1.0 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. In 2013 we completed a three-dimensional (“3D”) seismic shoot across Denton Field which will provide further insight into the development opportunities that may exist in this area. We are the operator of the Lea County assets.

Wyoming Properties

Hilight Field is located in the Powder River Basin in Campbell County, Wyoming, and consists of the Central Hilight Unit, the Grady Unit and the Jayson Unit. Hilight Field was discovered in 1969, unitized in 1971 and 1972, and underwent waterflood between 1972 and the mid-1990s. We have a 98.5% working interest in the Central Hilight Unit, an 82.5% working interest in the Grady Unit and an 82.7% working interest in the Jayson Unit. The Central Hilight, Grady and Jayson units and adjacent leasehold cover an area of almost 51,600 gross (47,400 net) acres. Our predecessor company acquired Hilight Field as part of a corporate acquisition in 2008 and initial activities were based primarily 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 projects which could moderate the natural decline of this field.

As of December 31, 2014, there were 151 gross (143.5 net) producing vertical wells and 6 gross (5.6 net) horizontal wells. Gross cumulative production through December 31, 2014, from our three operated units was 68.4 MMBbl of oil and 168 billion cubic feet of gas. During 2014, production from Hilight Field averaged 1,770 Boe per day and was 29% oil.

The Powder River Basin is experiencing a transformation due to horizontal drilling targeting oil-bearing formations such as the Turner, Niobrara, Shannon, Sussex, Parkman and Mowry. Along with these unconventional opportunities, the basin continues to see exploration activity targeting the conventional Minnelusa formation. We have focused our geological, geophysical and engineering efforts to prepare for testing these formations. These activities have included a 3D seismic survey of Hilight Field and the review of our extensive log data and data from operators drilling wells close to Hilight. In the fourth quarter of 2013 we successfully completed a horizontal well in the Turner formation. Based on this success, we drilled two additional wells in the Turner formation in the second quarter of 2014, which we completed during the third quarter of 2014. We believe there are 42 additional horizontal drilling locations in the Turner on our leasehold, based on 320-acre spacing. While drilling our recent wells we collected additional petrophysical data in the Parkman, Shannon, Sussex and Niobrara formations. We believe there may be more than 30 potential Parkman horizontal locations on our acreage, assuming 320-acre spacing.

In the Big Horn Basin, we own leases covering approximately 34,700 net acres that may be prospective for production from multiple formations including the Mowry, Frontier and Phosphoria. Pursuant to the July 2014 Exploration Agreement with an independent exploration and production company, the partnering company formed the approximately 25,000 acre Alvarado Federal Unit of which Resolute holds approximately 22% of the unit leasehold. At the end of 2014, the operator was in the process of completing the initial horizontal unit well in the Phosphoria formation. If the initial well is not economic, then a replacement well must be drilled in order to hold the unit.

Divestiture of North Dakota Properties

In 2013 we sold all of our non-operated properties located in the Bakken trend of North Dakota through three separate transactions for net proceeds of approximately $70.1 million. In March 2014 we sold our remaining operated properties in North Dakota for approximately $6.6 million.

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, 2014, 2013 and 2012 according to 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,		
	2014	2013	2012
Net proved developed reserves			
Oil (MBbl)	34,359	38,791	39,288
Gas (MMcf)	25,775	29,488	25,568
NGL (MBbl)	2,791	3,136	2,668
MBoe [(1)]	41,446	46,842	46,217
Net proved undeveloped reserves			
Oil (MBbl)	29,356	8,720	23,269
Gas (MMcf)	11,023	12,901	22,153
NGL (MBbl)	1,579	1,681	5,596
MBoe [(1)]	32,772	12,552	32,557
Total net proved reserves			
Oil (MBbl)	63,715	47,511	62,557
Gas (MMcf)	36,798	42,389	47,721
NGL (MBbl)	4,370	4,817	8,264
MBoe [(1)]	74,218	59,394	78,774
PV-10 ($ in millions) [(2)(3)]	973	1,054	1,127
Discounted future income taxes ($ in millions)	(140)	(161)	(255)
Standardized measure ($ in millions) [(2)(4)]	833	893	872

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, 2014 and 2013, were determined utilizing prices equal to the respective twelve-month unweighted arithmetic average of first day of the month prices, resulting in an average NYMEX WTI oil price of $94.99 and $96.94 per Bbl for the Aneth Properties and Plains Marketing, L.P. WTI oil price of $91.48 and $93.42 per Bbl for the Permian and Wyoming Properties, and an average Henry Hub spot market gas price of $4.35 and $3.67 per MMBtu, respectively. At December 31, 2012, we used an average NYMEX WTI oil price of $94.71 per Bbl and an average Henry Hub spot market gas price of $2.76 per 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 are 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, which, in the case of year-end 2014 estimates, are significantly in excess of prevailing prices. 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 level of 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.

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.

Facility construction and well development activities began on CO_2 flood projects in Aneth and McElmo Creek Units in 2006, with CO_2 injection commencing in 2007, and are ongoing. No CO_2 flood project proved undeveloped reserves were converted to proved developed in 2014. However, during 2013, we converted approximately 2.2 MMBoe of Aneth Field reserves to proved developed from the undeveloped category as a result of continued CO_2 response and drilling.

During 2014, 19 MBoe of proved undeveloped reserves were converted into proved developed as a result of successful non-operated drilling. Our operated drilling focus in 2014 was to preserve term leasehold acreage in the Permian Properties exclusively targeting non-proved locations. As a result, while non-proved properties were converted to proved reserves, no additional proved undeveloped reserves were converted to proved developed. 1.6 MMBoe proved developed and 6.0 MMBoe proved undeveloped were added as a result of 2014 drilling.

With respect to the properties included in our prior year reserve reports, we incurred development costs of $50.3 million in 2014 as compared to $97.3 million in 2013. The year over year change in developmental costs is also reflective of our operated drilling focus in 2014 to preserve term leasehold acreage in the Permian Basin. With respect to the total proved value, seven gross horizontal proved undeveloped drilling locations are scheduled to be drilled after some corresponding portion of primary term leasehold within each is set to expire. The Company has an initiative underway to amend and extend these leases to deal with potential expirations over the next one to two years. Without securing lease extensions on these seven Permian Basin locations, total proved reserves would be adversely affected by 1.6% on a volumetric basis and 0.9% on a value basis.

At December 31, 2014, no proved undeveloped reserves have remained, or are scheduled to remain, undeveloped beyond five years from its corresponding initial booking date.

Changes in Proved Reserves

Proved reserves reported by us at December 31, 2014, increased from those reported at December 31, 2013, as follows:

	Oil Equivalent (MBoe)
Proved reserves as of December 31, 2013	59,394

Production	(4,647)
Extensions, discoveries and other additions	28,800
Sales of minerals in place	(224)
Revisions of previous estimates	(9,105)
Proved reserves as of December 31, 2014	74,218
Proved undeveloped reserves:	
As of December 31, 2014	32,772
As of December 31, 2013	12,552

Extensions, discoveries and other additions to proved reserves were the result of drilling wells in the Permian and Powder River basins and the addition of CO_2 enhanced recovery projects in Aneth Field. Sales of minerals in place reflect the divestiture of certain properties in the Bakken and the Midland Basin.

Approximately 21.1 MMBoe have been added as proved undeveloped, comprised of four CO_2 injection projects in the Aneth Field Properties. Additionally, the Permian and Powder River basin properties had active drilling programs in 2014, resulting in 1.7 MMBoe added to proved developed producing from successful drilling of non-proved locations. Furthermore, these successful wells created additional proved undeveloped offset locations carrying 6.0 MMBoe reserves.

In accordance with SEC requirements, the oil reserves at December 31, 2014 and 2013, utilized average NYMEX West Texas Intermediate oil prices of $94.99 and $96.94 per Bbl, respectively, for the Aneth Properties and average Plains Marketing, L.P. West Texas Intermediate oil price of $91.48 and $93.42 per Bbl, respectively, for the Permian and Wyoming Properties. For natural gas, the reserves at December 31, 2014 and 2013, utilized average Henry Hub spot marketing gas prices of $4.35 and $3.67 per MMBtu, respectively. All prices then were adjusted for quality and basis differentials.

Controls Over Reserve Report Preparation, Technical Qualification and Methodologies Used

Reserve estimates as of December 31, 2014, were prepared by Resolute and audited by NSAI, our independent petroleum engineers. 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 Corporate Reserves Manager, Mr. Michael R. White. Mr. White has more than 30 years of experience in the oil and gas industry including general reservoir engineering, corporate engineering, exploration support and economic analysis support. During his career, Mr. White has resided and worked in Texas, Louisiana, Florida and Colorado. Additionally, he has performed evaluations in other basins in the states of Utah, Wyoming, North Dakota, and Washington. He has onshore, shallow water, and deep water project experience. Mr. White has a Bachelor of Science degree in Petroleum Engineering from Mississippi State University (1984) and a Masters of Business Administration from the University of Houston (1997). He is a Registered Professional Engineer in the states of Colorado, Texas and Wyoming. His qualifications meet or exceed the qualifications of reserve estimators and auditors as set forth in the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers. Mr. White is a member of the Society of Petroleum Engineers and is currently a director of the Society of Petroleum Evaluation 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.

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 T. Miller. Mr. Miller has been practicing consulting petroleum engineering at NSAI since 1997. He is a Registered Professional Engineer in the states of Texas, Louisiana and Wyoming and has more than 33 years of practical experience in petroleum engineering, with more than seventeen 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.

A report of NSAI regarding its audit of the estimates of proved reserves at December 31, 2014, 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 2014, 2013 and 2012.

	Year Ended December 31,		
	2014	2013	2012
Sales Data:			
Oil (MBbl)	3,488	3,499	2,773
Gas (MMcf)	5,023	4,565	3,567
NGL (MBbl)	320	207	41
Combined volumes (MBoe)	4,645	4,467	3,409
Daily combined volumes (Boe per day)	12,727	12,239	9,313
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$84.28	$91.75	$86.70
Gas ($/Mcf)	5.23	4.70	4.57
NGL ($/Bbl)	28.58	35.18	37.98
Average Production Costs ($/Boe):			
Lease operating expense	$24.26	$23.12	$23.45
Production and ad valorem taxes	8.01	9.04	10.48

In each of the years presented above, total estimated proved reserves attributed to our Aneth Field exceeded fifteen percent of our total proved reserves expressed on an equivalent basis. Therefore, the table below summarizes our operating data for Aneth Field for 2014, 2013 and 2012.

	Year Ended December 31, 2014	2013	2012
Sales Data:			
Oil (MBbl)	2,249	2,238	2,263
Gas (MMcf)	276	52	361
NGL (MBbl)	—	—	—
Combined volumes (MBoe)	2,295	2,246	2,323
Daily combined volumes (Boe per day)	6,287	6,154	6,347
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$84.76	$91.55	$87.61
Gas ($/Mcf)	4.76	5.64	7.01
NGL ($/Bbl)	—	—	—
Average Production Costs ($/Boe):			
Lease operating expense	$27.08	$28.33	$26.84
Production and ad valorem taxes	11.04	12.18	12.56

Oil and Gas Wells

The following table sets forth information as of December 31, 2014, 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 337 gross (214 net) active water and CO_2 injection wells as of December 31, 2014.

	Productive Wells[(1)] Gross	Net
Oil	779	591
Gas	6	5
Total	785	596

1) We operated 741 gross (580 net) productive wells at December 31, 2014.

Drilling Activity

The following table sets forth information with respect to exploration, development and extension wells we completed during 2014, 2013 and 2012. 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,		
	2014	2013	2012
Gross exploration wells:			
Productive [1][3]	1	—	43
Dry [2]	—	—	—
Total exploration wells	1	—	43
Gross development wells:			
Productive [1][3]	8	40	20
Dry [2]	—	—	—
Total development wells	8	40	20
Gross extension wells:			
Productive [1][3]	11	4	—
Dry [2]	—	—	—
Total extension wells	11	4	—
Total gross wells drilled	20	44	63

	Year Ended December 31,		
	2014	2013	2012
Net exploration wells:			
Productive (1)(3)	—	—	12
Dry (2)	—	—	—
Total exploration wells	—	—	12
Net development wells:			
Productive (1)(3)	4	30	12
Dry (2)	—	—	—
Total development wells	4	30	12
Net extension wells:			
Productive (1)(3)	6	3	—
Dry (2)	—	—	—
Total extension wells	6	3	—
Total net wells drilled	10	33	24

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.
3) Included in this 2013 count are 8 gross (1.9 net) productive development wells sold to HRC Energy, LLC effective March 1, 2013, closed July 15, 2013.

Acreage

All of our leasehold acreage is categorized as developed or undeveloped. The following table sets forth information as of December 31, 2014, relating to our leasehold acreage.

	Developed Acreage (1)	
Area	Gross (2)	Net (3)
Hilight Field (WY)	49,608	45,421
Aneth Field (UT)	43,218	27,157
Permian Basin (TX)	15,904	11,896
Permian Basin (NM)	4,690	3,971
North Dakota	516	99
Hilight area non-unit acreage (WY)	800	800
Big Horn Basin (WY)	1,357	1,357
Total	116,093	90,701

	Undeveloped Acreage (4)	
Area	Gross (2)	Net (3)
Aneth Field (UT)	1,173	1,173
Big Horn Basin (WY)	81,037	33,350
Permian Basin (TX)	15,947	9,146
Black Warrior Basin (AL)	13,633	6,783
North Dakota	640	301
Hilight area non-unit acreage (WY)	1,240	1,240
Total	113,670	51,993

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.

Approximately 18,300 net acres, 15,300 net acres and 9,300 net acres of undeveloped acreage expire in 2015, 2016 and 2017, respectively. Approximately 9,800 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, 2014, reserve report.

Present Activities

As of December 31, 2014, we were in the process of drilling 1 gross (0.7 net) well and there were 2 gross (1.2 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. That transaction was closed and paid for in two equal installments, each for 5%, that took place in July 2012 and January 2013, each with an effective date of January 1, 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 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

Crude Oil Sales

Aneth Field. We currently sell all of our oil from our Aneth Field Properties to Western under a purchase agreement dated July 2014. On December 31, 2014, the Company entered into an amendment to the purchase agreement with Western, which provides for Resolute to receive a price equal to the NYMEX oil price minus a differential of $8.00 per barrel of oil. The amendment also provides that the term of the purchase agreement shall continue automatically after December 31, 2014, until March 31, 2015, and thereafter on a month-to-month basis until terminated by a party with ninety days prior notice. If, for any reason, Western is unable to process our oil, there is alternative access to markets through rail and truck facilities or, in early 2015, through the FERC-regulated Texas-New Mexico pipeline owned by Western.

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 9,800 barrels of oil per day as of year-end. When combined with the royalty barrels owned by the Navajo Nation, Aneth Field provides approximately 12,000 barrels per day to the Gallup refinery, nearly 50% of total refinery capacity.

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 and rail from the Aneth Field Properties to markets throughout the United States. 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 approximately equal to the current differential realized in the price received from Western.

Other fields. With respect to our oil production from all other fields, we generally sell our crude oil under 30-day contracts at the best available price in the area.

Gas and NGL Sales

Our gas and NGL are sold to various midstream processing companies under long-term percent of proceeds contracts.

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.

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. For a more detailed discussion, please read –"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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, nearly complete dismantling of inactive gas plant buildings and facilities and limited remediation of hydrocarbon-affected soil.

As of December 31, 2014, 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 $25.7 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, 2014. Demolition activities were materially completed at December 31, 2014. These costs do not include any costs for clean-up or remediation of the subsurface as well as minor additional demolition and removal activity associated with buried piping and concrete foundations. 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 statute. 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 agreement 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.”

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 although our operations may be affected by extreme weather.

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.

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 or threat of release of CERCLA “hazardous substances” into the environment. These persons include the current and former owners and operators 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 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 CERCLA’s definition of hazardous substances, as well as under the Navajo Nation CERCLA which, unlike the federal CERCLA, broadly 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.

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 may 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, and an 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 federal, 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, and a draft PSD permit was released for public comment in the fourth quarter of 2014, which we commented upon. 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 2015 by the EPA, although the EPA has given us no definite confirmation, and such termination may not be possible until revised final PSD and Title V permits are issued.

On July 1, 2011, the 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). These rules became effective on August 30, 2011 and were subsequently amended, and establish the phased implementation of a program of minor source permitting by the EPA in Indian Country over a period of 48 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 48 months from the effective date of the rules (although they need to be registered with the 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 evaluated our existing and planned new sources in Indian Country for purposes of registering them, applying for permits as appropriate 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 the 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 established specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment as well as 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 in 2013 issued revised rules that were responsive to some industry concerns. On December 31, 2014, the EPA issued still further final revisions in response to stakeholder petitions for reconsideration of various regulatory provisions. Some of these final revisions are also now the subject of petitions for still further administrative reconsideration, specifically including petitions regarding the applicability of new source performance standards to tanks operated in parallel. These final revised rules issued in 2013 and 2014 require modifications to our operations as promulgated, increasing our capital and operating costs without being offset by increased product capture.

Actual air emissions reported for our facilities are in material compliance with the terms of existing air permits and the 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 on the discharge of “pollutants” into waters of the United States, including wetlands, without appropriate permits. Pollutants under the Clean Water Act, are defined to include produced water and sand, drilling fluids, drill cuttings, dredge and fill material, and other substances related to the oil and gas industry. 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. They also can impose substantial liability for the costs of removal or remediation associated with discharges of oil, hazardous substances or other pollutants.

The Clean Water Act also regulates stormwater discharges from industrial properties and construction sites, and requires separate permits and implementation of a Stormwater Pollution Prevention Plan (“SWPPP”) establishing best management practices, training, and periodic monitoring of covered activities. Certain operations also are required to develop and implement Spill Prevention, Control, and Countermeasure (“SPCC”) plans or facility response plans to address potential oil spills.

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 were obligated to complete the remedial activities required under the administrative order issued to ExxonMobil, at an estimated cost of approximately $100,000 per year. Onsite activities were concluded and a transition to passive monitoring was implemented in 2014 with final closure anticipated in 2016.

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. In 2009 and 2010, the EPA evaluated wellbores of producer and injector wells in Aneth Field and suggested that certain wells may not be adequately cased and / or cemented across the bottom of the underground source of drinking water. As a result, the Navajo EPA has required Resolute to perform remedial casing and cement work on selected wellbores concurrent with any significant well work on injection wells. In most cases, remedial work is limited to the affected injection well that is being worked over. In the case of new drills of injection wells or deepening of existing injection wells, the remedial action requirements could potentially impact identified deficient wellbores (producer or injector) within one-half mile of the well being drilled or deepened. Resolute estimates the cost to perform remedial activities, if and when required, could range from $100,000 to over $300,000 per deficient well.

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.

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 already have 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. 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 GHG emissions. 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 human-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. The mandatory reporting rule (MRR) and subsequent amendments included reporting requirements for 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. On November 13, 2014, the EPA finalized additional portions of the MRR. The new provisions went into effect on January 1, 2015, and included revised monitoring and data disclosure requirements for the petroleum and natural gas industry clarifying the that engines, boilers, heaters, flares, and separation and processing equipment are among the emission sources that must provide greenhouse gas reports. In addition, the EPA also issued a new proposed rule that would expand the types of sources that are covered by the MRR. These sources would include oil well completions and workovers with hydraulic fracturing, petroleum and natural gas gathering and boosting systems, and transmission pipeline blowdowns between compressor stations. Currently, the Aneth Field is the only asset operated by the Company that is subject to the MRR requirements. A number of states also 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.

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 and Development Committee of the Navajo Nation Council. The Resources and Development Committee (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.

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.

Taxation by 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 5% 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 Navajo EPA currently enforces these laws in conjunction with the 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. In 2008, we began 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 the 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, the 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 the Navajo Nation EPA, in addition to that information going to other spill reporting contacts within the Navajo Nation EPA.

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 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.

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, the Bureau of Land Management is proposing new regulatory requirements for fracing on certain federal lands, and a committee of the U.S. House of Representatives has commenced its own investigation into fracing practices. For example, on October 21, 2011, the EPA announced its intention to propose regulations under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing, and these proposed regulations are expected in early 2015. Also, EPA has initiated a stakeholder and potential rulemaking process under the Toxic Substances Control Act ("TSCA") to obtain data on chemical substances and mixtures used in hydraulic fracturing. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to such

TSCA rulemaking. The Bureau of Land Management (BLM) has also indicated its intent to pursue a rulemaking related to further controlling the venting and flaring of natural gas on BLM administered lands, and the U.S. Occupational Safety and Health Administration has proposed stricter standards for worker exposure to silica, which would apply to use of sand as a proppant for hydraulic fracturing. In addition, Congress has considered, and may in the future consider, legislation that would amend the Safe Drinking Water Act ("SDWA") to encompass hydraulic fracturing activities. Past proposed legislation would have required hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations, including disclosure of chemicals used in the fracturing process, 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 currently are waiting to see what requirements, if any, will be promulgated by the US Environmental Protection Agency, Bureau of Land Management and the Navajo Nation before disclosing similar information for wells fractured on Navajo lands.

Employees

As of December 31, 2014, we had 265 full-time employees, of which 47 were field level employees represented by the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union, or United Steel Workers ("USW") labor union, and are covered by a collective bargaining agreement that is subject pending to renewal negotiations. We believe that we have a satisfactory relationship with our employees.

Offices

We currently lease approximately 56,000 square feet of office space in Denver, Colorado and approximately 21,000 square feet of office space in Midland, Texas. Our principal offices is located at 1700 Lincoln, Suite 2800, Denver, CO 80203. In addition, we own and maintain field offices in Colorado, Utah, Wyoming and Texas and lease 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.

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, 1700 Lincoln, Suite 2800, Denver, Colorado 80203. 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.

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.

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 reductions 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;
- actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;
- weather conditions;
- overall domestic and global political and economic conditions;
- the price of foreign imports;
- political and economic conditions in oil producing countries, including the Middle East, Russia and South America;
- 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, 2014, the NYMEX price for light sweet crude oil ranged from a high of $107.26 per Bbl to a low of $53.27 per Bbl, and declined precipitously in the latter part of the year. For calendar year 2013, the range was from a high of $110.53 per Bbl to a low of $86.68 per Bbl, and for the five years ended December 31, 2014, the price ranged from a high of $113.93 per Bbl to a low of $53.27 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, reserves 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 repay indebtedness, finance capital expenditures, make acquisitions, raise capital and otherwise 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 and present values 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 and value of those reserves. Finally, our Revolving Credit Facility and our Secured Term Loan Facility both contain asset coverage maintenance covenants based on the ratios of total proved reserves to total secured debt and proved developed reserves to total secured debt. A reduction in our reserves can result in events of default under these debt agreements as a result of failure to comply with such ratios.

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 is subject to semi-annual redetermination by our lenders based on their evaluation of our proved reserves and their internal criteria. In addition, under certain circumstances, interim redeterminations may be conducted.

The significant recent decline in oil and gas prices has resulted in banks reducing the price decks upon which borrowing bases are set. Our current borrowing base was set using a price deck significantly higher than the current price deck used by the lending institutions in our syndicate. Therefore, it is likely that our borrowing base will be reduced, perhaps significantly, in the regular semi-annual redetermination upcoming in March 2015.

In the event the amount outstanding under our Revolving Credit Facility at any time exceeds the borrowing base at such time, we would be required to repay the amount of our outstanding borrowings exceeding the new borrowing base over the 120 days following the redetermination. 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, incur additional indebtedness, sell assets or sell additional debt or equity securities in order to cure such borrowing base deficiency. We may not be able to 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 and a cross default under our Secured Term Loan Facility and our Senior Notes.

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:

- 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;
- 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;
- may 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 and development 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.

Covenants in the indenture governing our Revolving Credit Facility, Secured Term Loan Facility and the Senior Notes, currently impose, and future financing agreements may impose, significant operating and financial restrictions.

The indenture governing our Revolving Credit Facility, Secured Term Loan Facility and the Senior Notes each contain restrictions, and future financing agreements 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 and equity offerings other than to repay indebtedness;

engage in transactions with our affiliates;
engage in sale and leaseback transactions;
merge or consolidate;
make payments from restricted subsidiaries;
sell equity interests of restricted subsidiaries; and
sell, assign, transfer, lease, convey or dispose of assets.

Our Revolving Credit Facility will mature in March 2018, unless extended, and is secured by substantially 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) do not permit our maximum senior secured leverage ratio (Revolving Credit Facility debt to consolidated Adjusted EBITDA as defined in the Revolving Credit Facility) to exceed 2.5 to 1.0 at the end of each fiscal quarter. The covenants in the Revolving Credit Facility and the Secured Term Loan Facility require, among other things, maintenance of certain ratios, measured on a quarterly basis, as follows: (i) secured debt to Adjusted EBITDA of no more than 3.5 to 1.0, (ii) PV-10 of total proved reserves to total secured debt of at least 1.1 to 1.0, rising over time to 1.5 to 1.0, and (iii) PV-10 of proved developed reserves to total secured debt of at least 1.0 to 1.0.

These restrictions may prevent us from taking actions that we believe would be in the best interest of our business, may require us to sell assets or take other actions to reduce indebtedness to meet our covenants, 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 provide assurance 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.

If we are unable to comply with the restrictions and covenants in the agreements governing the Revolving Credit Facility, Secured Term Loan Facility, Senior Notes and other debt, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and would impact our ability to make principal and interest payments on our debt.

If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness (including our Revolving Credit Facility, our Secured Term Loan Facility or the Senior Notes), we could be in default under the terms of the agreements governing such indebtedness, and any such default could cause a cross-default under the terms of our other indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders under our Revolving Credit Facility could elect to terminate their commitments, cease making further loans and our secured lenders could institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation. We may in the future need to seek to obtain waivers from the required lenders under our Revolving Credit Facility or Secured Term Loan Facility to avoid being in default. If we breach our covenants under our Revolving Credit Facility or Secured Term Loan Facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under our Revolving Credit Facility, Secured Term Loan Facility or Senior Notes, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation.

In addition, any default under the agreements governing our indebtedness, including a default under our Revolving Credit Facility Credit or Secured Term Loan Facility that is not waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make us unable to pay principal, premium, if any, and interest on the Senior Notes and other indebtedness and substantially decrease the market value of the Senior Notes.

Inadequate liquidity could materially and adversely affect our business operations.

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

- the price at which we sell our oil and gas production and the costs we incur to market our production;
- the amount of oil and gas we produce;
- our ability to borrow under our Revolving Credit Facility or future debt agreements;

debt service requirements contained in our Revolving Credit Facility, Senior Notes, Secured Term Loan Facility or future debt agreements;
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;
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.

In addition, our estimate of proved reserves as of December 31, 2014 was based on a pricing methodology required by SEC rules. This commodity price assumption used in calculating our reserves significantly exceeds the current market price of oil and gas. Therefore it is likely that we will have substantial downward adjustments in our estimated proved reserves in the future if the current low commodity price environment persists. Furthermore, if low 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. When we incur impairment charges in the future, we could have a material adverse effect on our results of operations in the period incurred. In addition, a reduction in the future net cash flow from our properties would negatively affect our ability to borrow funds under our Revolving Credit Facility. Finally, because our Revolving Credit facility and our Secured Term Loan facility contain covenants that require us to maintain certain asset coverage ratios, downward adjustments in our estimated proved reserves may result in defaults under such agreements.

We include estimates of quantities of oil and gas using certain terms, such as “resource,” “resource potential,” “EUR,” “oil in place,” or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC definition of proved, probable and possible reserves, and which the SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by Resolute. In addition, 24 hour peak IP rates and 30 day peak IP rates for both our wells and for those wells that are located near to our properties are limited data points in each well’s productive history and not necessarily indicative or predictive of future production rates, EUR or economic rates of return from such wells and should not be relied upon for such purpose.

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. On December 31, 2014, the Company entered into an amendment to the purchase agreement with Western dated July 2014, which provides for Resolute to receive a price equal to the NYMEX oil price minus a differential of $8.00 per barrel of oil. The amendment also provides that the term of the purchase agreement shall continue automatically after December 31, 2014, until March 31, 2015, and thereafter on a month-to-month basis until terminated by a party with ninety days prior notice. If, for any reason, Western is unable to process our oil, there is alternative access to markets through rail and truck facilities or, in early 2015, through the FERC-regulated Texas-New Mexico pipeline owned by Western.

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 9,800 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, 2014, and a NYMEX oil price of $70.00 per Bbl, Western could owe us between $6.2 million and $15.6 million. If Western defaults on its obligation to pay us for the oil we have delivered, our income would be materially and negatively affected.

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:

- reductions in oil or gas prices or increases in the differential between index oil or gas prices and prices received;
- high costs, shortages or delivery delays of rigs, equipment, labor or other services;
- unexpected operational events and/or conditions;
- 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, 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.

We and our subsidiary guarantors may be unable to fulfill our debt service obligations under our debt agreements.

We have a substantial amount of indebtedness. As a result, a significant portion of our cash flow will be required to pay interest and principal on our indebtedness, and we may not generate sufficient cash flow from operations, or have future borrowing capacity available, to enable us to pay amounts due on, or pay when due at maturity, our indebtedness, including the Secured Term Loan Facility or the Senior Notes, or to fund other liquidity needs. As of December 31, 2014, we have $785 million in outstanding indebtedness.

Servicing our indebtedness and satisfying our other obligations will require a significant amount of cash. Our cash flow from operating activities and other sources may not be sufficient to fund our liquidity needs. Our ability to pay interest and principal on our indebtedness and to satisfy our other obligations will depend upon our future operating performance and financial condition and the availability of refinancing indebtedness, which will be affected by prevailing economic and industry conditions and financial, business and other factors, many of which are beyond our control. We cannot assure you that our business will generate sufficient cash flow from operations, or that future borrowings will be available to us under our Revolving Credit Facility or otherwise, in an amount sufficient to fund our liquidity needs, including the payment of principal and interest on the Senior Notes or the Secured Term Loan Facility.

The recent decline in product prices has decreased our operating cash flow. That decrease or an increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including curtailing our exploration and drilling programs, selling assets, issuing equity, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of future debt agreements may, and our Revolving Credit Facility, the Secured Term Loan Facility and the indenture governing the Senior Notes do, restrict us from implementing some of these alternatives. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations or issue equity at depressed prices to meet our debt service and other obligations. We may not be able to consummate these dispositions or equity issuances for fair market value or at all. Furthermore, any proceeds that we could realize from any dispositions or equity issuances may not be adequate to meet our debt service obligations then due.

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, 2014, 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 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.

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.

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 asset sales, or some combination thereof, which may not be available to us.

For example, based on our SEC-case reserve projections, we expect to spend an additional $840.2 million of capital expenditures (including CO_2 purchases) cover the next 29 years to implement and complete our proved developed non-producing and proved undeveloped projects. We expect to incur approximately $624.8 million of these future capital expenditures between 2015 and 2019 based on the capital plan contemplated by our December 2014 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, the Senior Notes or the Secured Term Loan Facility, 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.

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 and our Secured Term Loan 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.

Notwithstanding our current indebtedness levels and restrictive covenants, we may still be able to incur substantial additional debt or make certain restricted payments, which could exacerbate the risks described above.

We may be able to incur additional debt in the future. In addition, although the Revolving Credit Facility, the Secured Term Loan Facility and the indenture governing the Senior Notes contain restrictions on our ability to incur indebtedness, those restrictions are subject to a number of exceptions. In particular, we may borrow under our senior credit facilities, including the Revolving Credit Facility. Also, we expect to be able to issue additional notes under the indenture in some circumstances. In addition, if we are able to designate some of our restricted subsidiaries under the indenture as unrestricted subsidiaries, including in connection with the formation of e.g., master limited partnerships, those unrestricted subsidiaries would be permitted to borrow beyond the limitations specified in the indenture and engage in other activities in which restricted subsidiaries may not engage. We may also consider investments in joint ventures or acquisitions that may increase our indebtedness. Also, under the indenture, we will be able to make restricted payments in certain circumstances. Adding new debt to current debt levels or making otherwise restricted payments could intensify the related risks that we and our subsidiaries now face.

Although the Senior Notes are referred to as “senior” rights to receive payments on the Senior Notes is effectively subordinated to the rights of our and our restricted subsidiaries’ existing and future secured creditors.

The lenders under our Revolving Credit Facility and Secured Term Loan Facility will have claims that are prior to the claims of holders of the Senior Notes to the extent of the value of the assets securing the Revolving Credit Facility and the Secured Term Loan Facility. The Revolving Credit Facility and the Secured Term Loan Facility are secured by liens on substantially all of our assets and the assets of our restricted subsidiaries. The Senior Notes are effectively subordinated to any secured indebtedness incurred under the Revolving Credit Facility or the Secured Term Loan Facility. In the event of any distribution or payment of our or any guarantor’s assets in any foreclosure, dissolution, winding-up, liquidation, reorganization or other bankruptcy proceeding, holders of secured indebtedness will have prior claim to those of our or our restricted subsidiaries’ assets that constitute their collateral. Holders of Senior Notes will participate ratably with all holders of our unsecured indebtedness that is deemed to be of the same class as such notes, and potentially with all of our or any restricted subsidiary’s other general creditors, based upon the respective amounts owed to each holder or creditor, in our remaining assets. In any of the foregoing events, we cannot assure you that there will be sufficient assets to pay amounts due on the Senior Notes. As a result, holders of Senior Notes may receive less, ratably, than holders of secured indebtedness.

The Senior Notes will be subordinated to all indebtedness of those of our existing or future subsidiaries that are not, or do not become, guarantors of the notes.

Although all of our current subsidiaries are guarantors of the Senior Notes, if any future subsidiaries do not become guarantors of the notes, they will have no obligation, contingent or otherwise, to pay amounts due under the notes or to make any funds available to pay those amounts, whether by dividend, distribution, loan or other payment. The notes will be structurally subordinated to all indebtedness and other obligations of any non-guarantor subsidiary such that, in the event of insolvency, liquidation, reorganization, dissolution or other winding up of any subsidiary that is not a guarantor, all of the subsidiary’s creditors (including trade creditors and preferred stockholders, if any) would be entitled to payment in full out of the subsidiary’s assets before we would be entitled to any payment. In addition, the indenture governing the notes will, subject to some limitations, permit non-guarantor subsidiaries to incur additional indebtedness and will not contain any limitation on the amount of other liabilities, such as trade payables, that may be incurred by these subsidiaries.

We may not be able to repurchase the Senior Notes upon a change of control as required by the indenture governing the notes. A change of control is also an event of default under our Revolving Credit Facility and our Secured Term Loan Facility.

Upon the occurrence of certain kinds of change of control events, we will be required to offer to repurchase all outstanding Senior Notes at 101% of the principal amount thereof plus accrued and unpaid interest, if any, to the date of repurchase, unless all notes have been previously called for redemption. The holders of other debt securities that we may issue in the future, which rank equally in right of payment with the notes, may also have this right. Our failure to purchase tendered notes would constitute an event of default under the indenture governing the notes, which in turn, would constitute an event of default under our Revolving Credit Facility and our Secured Term Loan Facility.

Therefore, it is possible that we may not have sufficient funds at the time of the change of control to make the required repurchase of notes. Moreover, our Revolving Credit Facility and our Secured Term Loan Facility restrict, and any future indebtedness we incur may restrict, our ability to repurchase the notes, including following a change of control event. As a result, following a change of control event, we would not be able to repurchase notes unless we first repay all indebtedness outstanding under our Revolving Credit Facility, our Secured Term Loan Facility and any of our other indebtedness that contains similar provisions, or obtain a waiver from the holders of such indebtedness to permit us to repurchase the notes. We may be unable to repay all of that indebtedness or obtain a waiver of that type. Any requirement to offer to repurchase outstanding notes may therefore require us to refinance our other outstanding debt, which we may not be able to do on commercially reasonable terms, if at all. These repurchase requirements may also delay or make it more difficult for others to obtain control of us.

In addition, the occurrence of a change of control (as defined under the respective debt agreements) in itself would constitute an event of default under our Revolving Credit Facility and our Secured Term Loan Facility. This may also delay or make it more difficult for others to obtain control of us.

In addition, certain important corporate events, such as leveraged recapitalizations that would increase the level of our indebtedness, may not constitute a "Change of Control" under the indenture.

Following a sale of "substantially all" of our assets, we may not be able to determine if a change of control that would give rise to a right to have the Senior Notes repurchased has occurred or if a change of control that would give rise to an event of default under the Revolving Credit Facility or the Secured Term Loan Facility has occurred.

The definition of change of control in the Revolving Credit Facility, the Secured Term Loan Facility and the Indenture all include a phrase relating to the sale of "all or substantially all" of our assets. There is no precise, established definition of the phrase "substantially all" under applicable law. Accordingly, the ability of a holder of Senior Notes to require us to repurchase its notes, and the occurrence of an event of default under the Revolving Credit Facility and the Secured Term Loan Facility, as a result of a sale of less than all our assets to another person, may be uncertain. Further, a holder or holders of Senior Notes could take the position that a transaction or series of transactions constituted a "sale of substantially all assets" giving rise to the right to have the Senior Notes repurchased.

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, 2014, approximately 55% 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 Navajo tribal lands.

Substantially all of our Aneth Field Properties, which represent approximately 58% of our 2014 oil and gas revenues and 73% of our total net proved reserves at December 31, 2014, 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.

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.

An incident 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.”

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 current interest in the Ratherford Unit.

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."

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.

An economic slowdown could lead to lower demand for crude oil and gas by individuals and industries, which may 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 Revolving Credit Facility and our Secured Term Loan Facility bear floating interest rates based on the London Interbank Offered Rate, or LIBOR. If LIBOR were to increase, this would cause higher interest expense for unhedged levels of LIBOR-based borrowings.

Our Revolving Credit Facility requires the lenders to re-determine 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 and could require us to repay any amounts outstanding in excess of the then-determined borrowing base.

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

A financial failure by us or our subsidiaries may result in the assets of any or all of those entities becoming subject to the claims of all creditors of those entities.

A financial failure by us or our subsidiaries could affect payment of the Revolving Credit Facility, the Secured Term Loan Facility and the Senior Notes if a bankruptcy court were to substantively consolidate us and our subsidiaries. If a bankruptcy court substantively consolidated us and our subsidiaries, the assets of each entity would become subject to the claims of creditors of all entities. This would expose holders of Senior Notes not only to the usual impairments arising from bankruptcy, but also to potential dilution of the amount ultimately recoverable because of the larger creditor base. Furthermore, forced restructuring of the Senior Notes could occur through the "cramdown" provisions of the bankruptcy code. Under these provisions, the notes could be restructured over the objections of holders as to their general terms, primarily interest rate and maturity.

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.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

The drilling process and the results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no drilling or production history and, consequently, we are more limited in assessing future drilling costs and results in these areas. If our drilling costs are greater or our results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce gas or oil from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.

As of December 31, 2014, 44% of our total estimated proved reserves were classified as proved undeveloped. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves as a result of such factors or otherwise could cause us to have to reclassify our PUDs as unproved reserves. Further, we may be required to write down our PUDs if we do not drill those wells within five years after their respective dates of booking.

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 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. Although oil and gas prices have recently declined significantly, making such shortages less impactful at the present time, we could experience such difficulties in the future. In that event, our profit margin, cash flow and operating results could be adversely affected and our ability to conduct our operations in accordance with our plans and budgets could be restricted.

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 expansion of GHG mandatory reporting rules (MRR) and proposed GHG cap-and-trade legislation are two examples of proposed changes in the regulatory climate that would affect us. Also, the EPA has announced a comprehensive strategy for further reducing methane emissions from oil and gas operations, with a proposed rule expected in 2015 and a final rule in 2016. We may be placed at a competitive disadvantage to larger companies in the industry with respect to such expanded regulatory requirements, 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 incentives currently available to companies engaged in oil and gas development and production. These changes include (i) the elimination of the current deduction for intangible drilling and development costs and for qualified tertiary injectant expenses, (ii) the repeal of the percentage depletion allowance for oil and gas wells, (iii) the elimination of the domestic manufacturing deduction, and (iv) the extension of the amortization period for certain geological and geophysical expenditures. The passage of this legislation or any similar changes in U.S. federal income tax laws could increase the cost of exploration and development of oil and gas resources. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

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

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 often is 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. Current regulation of hydraulic fracturing primarily is conducted at the state level through permitting and other compliance requirements, but proposed regulations at the federal level are being considered by EPA, BLM and OSHA. The U.S. Congress currently is also considering legislation that would amend the SDWA 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. If adopted, the proposed amendment to the SDWA or these federal agencies' possible expansion of their regulatory programs affecting hydraulic fracturing 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 and public referendums for moratoriums or additional restrictions on fracing have recently been presented in many state and local jurisdictions. Additional regulations and permitting requirements could lead to significant operational delays and increased operating costs, and make it more difficult to perform hydraulic fracturing.

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.

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.

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 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 Revolving Credit Facility, cash generated by operations and the issuance of the Senior Notes. We could finance future acquisitions utilizing similar financing sources, which may include amending our Revolving 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 additional indebtedness could have material adverse effects on our financial condition and liquidity and limit our future flexibility and growth opportunities.

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 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;
- 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 us 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.

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 its option to purchase an additional 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.

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 58% of our 2014 oil and gas revenues and 73% of our total proved reserves at December 31, 2014, 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 Permian and Wyoming properties. As a result of our lack of diversification in asset type and location, any delays or interruptions of production caused by such factors as governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation, price fluctuations, natural disasters or shutdowns of the pipelines connecting our production to refineries would have a significantly greater impact on our results of operations than if we possessed more diverse assets and locations.

The prices we receive for our oil and gas production are affected by the geographic region in which that production is located. 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, 2014, we had approximately 9,100 net acres in the Permian Basin, and 33,400 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.

If the expenses associated with the operator's activity exceed our expectations we may be required to make significantly higher capital contributions to satisfy our proportionate share of the costs. If such capital contributions are required, we may not be able 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 a joint operating agreement or any other agreements relating to properties we do not operate, our respective ownership interest could be diluted or forfeited.

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 mark-to-market 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 mark-to-market 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 estimate, we 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 purchasers, 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 its 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 and our Secured Term Loan Facility require us to enter into derivative agreements covering at least 70% of our anticipated production from proved properties on a rolling twenty four month basis, but prohibit 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 Revolving Credit Facility. 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.

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. $25.7 million has already been incurred and paid for as of December 31, 2014. This estimate does not include any costs for any possible subsurface clean-up or remediation of the site, as well as minor additional demolition and removal activities associated with buried piping and concrete foundations, which may be significant.

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

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 human-caused 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 has considered, and in the future may consider, 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 v. EPA and subsequent decisions, the EPA also may regulate GHG emissions from mobile and stationary sources even if Congress does not adopt new legislation specifically authorizing such regulation. Most recently, in June 2014, the United States Supreme Court invalidated part of the EPA's stationary source GHG program in Utility Air Regulatory Group v. EPA, but the Supreme Court also ruled that major sources subject to the PSD or Title V programs because of non-GHG pollutant emissions could be subjected to certain "best available control technology" requirements imposed to curb their GHG emissions, and EPA is proceeding to develop regulations for power plants based on this GHG regulatory authority identified in that decision. Further, the EPA has announced a comprehensive strategy for further reducing methane emissions from oil and gas operations, with a proposed rule expected in 2015 and a final rule in 2016. Other nations already have 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 source performance standard air emission controls for oil and gas production and gas processing operations. After several parties challenged these regulations in court, the EPA administratively reconsidered certain requirements. As a result of such administrative reconsideration, the EPA issued final amendments to the regulations in September 2013 and December 2014, and is evaluating whether further reconsideration is warranted. Specifically, the EPA's rule package currently 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 processing 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 gas 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. On December 17, 2014, the EPA also proposed to revise and lower the existing 75 ppb national ambient air quality standard (''NAAQS'') for ozone under the federal Clean Air Act to a range within 65-70 ppb, and taking public comment on whether the ozone standard should be revised as low as 60 ppb. A lowered ozone NAAQS in a range of 60-70 ppb could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements for new sources, and increased permitting delays and costs. These rules and standard revisions could require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells.. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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, 2014, 47 of our field level employees were represented by the USW, and covered by a collective bargaining agreement, which is in the process of renewal negotiations. 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.

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

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, distribution and accounting 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.

Conservation measures and technological advances could reduce demand for oil and gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and gas. The impact of the changing demand for oil and gas could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. Oil and gas activities in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various species and their habitat. The U.S. Fish and Wildlife Service in May 2014 proposed a rule to alter how it identifies critical habitat for endangered and threatened species. It is unclear when this rule will be finalized. Seasonal restrictions could limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which could lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures and could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

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 (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 that could have a negative effect on the trading price of the shares of our common stock.

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

Our amended and restated charter and bylaws have provisions that could 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 holder of our common stock will be able to resell the common stock purchased at a price in excess of the purchase price.

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 are significantly affected by commodity prices for oil and gas. In particular, our stock price was very volatile during 2014, trading between $9.65 and $1.00 per share. 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 a price exceeding the purchase price.

We are currently not in compliance with the New York Stock Exchange's requirements for continued listing, and therefore may be delisted, which may decrease our stock price and would have a material adverse effect on our liquidity and our business.

On February 3, 2015, we received a letter from the New York Stock Exchange ("NYSE") notifying us that we no longer met the NYSE's requirements for continued listing under New York Stock Exchange Listed Company Manual Rule 802.01C (the "Stock Price Rule"), because the average closing price our common stock did not equal or exceed $1.00 per share over a period of 30 consecutive trading days prior to the date of the notification letter. Per the NYSE Listed Company Manual Rule 802.01C, we were afforded six months to regain compliance with the Stock Price Rule. However, if we are not able to regain compliance in the applicable time period, the NYSE will provide written notification to us that our common stock would be subject to delisting from the NYSE.

While we intend to monitor the closing price and average closing price of our common stock and consider available options if our common stock does not trade at a level likely to result in us regaining compliance with the Stock Price Rule by [August 3, 2015] or within any applicable extension period, no assurances can be made that we will in fact be able to comply and that our common stock will remain listed on the NYSE. If our common stock is delisted from the NYSE, such delisting could negatively impact the market price of our common stock, reduce the number of investors willing to hold or acquire our common stock, and limit our ability to issue additional securities or obtain additional financing in the future, and might negatively impact our reputation and, as a consequence, our business.

If our common stock were delisted and determined to be a “penny stock,” a broker-dealer may find it more difficult to trade our common stock and an investor may find it more difficult to acquire or dispose of our common stock in the secondary market.

If our common stock were removed from listing on the NYSE, it may be subject to the so-called “penny stock” rules. The SEC has adopted regulations that define a “penny stock” to be any equity security that has a market price per share of less than $5.00, subject to certain exceptions, such as any securities listed on a national securities exchange. For any transaction involving a “penny stock,” unless exempt, the rules impose additional sales practice requirements on broker-dealers, subject to certain exceptions. If our common shares were delisted and determined to be a “penny stock,” a broker-dealer may find it more difficult to trade our common stock and an investor may find it more difficult to acquire or dispose of our common stock in the secondary market. These factors could significantly negatively affect the market price of our common stock and our ability to raise capital.

Future sales of our common stock in the public or private markets could adversely affect the trading price of our common stock, substantially dilute existing stockholders and our ability to continue to raise funds in new equity offerings.

Future sales of our common stock, or securities convertible into or exercisable for, our common stock in public or private offerings could result in substantial dilution to existing stockholders, could potentially adversely affect the trading price of our common stock and could impair our ability to raise capital through future offerings of securities. This is particularly true if such sales occur at depressed stock prices, such as those currently existing. In addition, the perceived risk of dilution may cause some stockholders to sell their shares, which may further reduce the market price of our common stock.

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.

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, 2014 and 2013. The closing price of the common stock on February 27, 2015 was $1.06.

	2014		2013	
Period	High	Low	High	Low
1st Quarter	$9.65	$6.45	$11.56	$8.21
2nd Quarter	$8.98	$6.85	$11.54	$7.41
3rd Quarter	$8.77	$6.21	$9.10	$7.70
4th Quarter	$6.25	$1.00	$10.97	$8.06

As of February 27, 2015, there were approximately 245 record holders of our common stock.

Our warrants were listed on the New York Stock Exchange under the symbol "RENWS." However, at December 31, 2014, no warrants remain outstanding as all warrants expired on September 25, 2014.

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.

2014	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)
March	162,875	$ 9.16	—	—
April	3,933	$ 7.14	—	—
May	983	$ 7.49	—	—
June	2,251	$ 8.24	—	—
July	969	$ 8.56	—	—
August	17,048	$ 7.56	—	—

October	3,442	$ 5.93	—	—
December	23,441	$ 1.33	—	—

1) All shares purchased in 2014 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, 2014, the maximum number of shares that may yet be purchased would not exceed the employees' portion of taxes withheld on unvested shares (3,529,080 common shares), shares yet to be granted under the Incentive Plan (2,030,560 shares) and potential Outperformance Shares (827,985 shares).

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 agreements and our indenture covering the Senior 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 Revolving Credit Facility, Secured Term Loan, Senior Notes, 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 on the New York Stock Exchange over the five-year period ended December 31, 2014, 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 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

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial data for each of the four years ended December 31, 2014. 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,				
	2014	2013	2012	2011	2010
	(in thousands, except per share data)				
Statement of Operation Data:					
Revenue	$329,371	$349,779	$258,268	$226,908	$173,395
Operating expenses	442,045	483,647	218,084	169,473	142,225
Income (loss) from operations	(112,674)	(133,868)	40,184	57,435	31,170
Other income (expense)	86,684	(44,617)	(10,327)	(9,080)	(22,597)
Income (loss) before income taxes	(25,990)	(178,485)	29,857	48,355	8,573
Income tax benefit (expense)	4,140	64,679	(11,881)	(17,870)	(2,388)
Net income (loss)	(21,850)	(113,806)	17,976	30,485	6,185
Earnings (loss) per share:					
Common stock, basic	$(0.30)	$(1.67)	$0.30	$0.53	$0.12
Common stock, diluted	$(0.30)	$(1.67)	$0.30	$0.47	$0.12
Weighted average shares outstanding:					
Common stock, basic	73,798	68,260	59,424	57,612	49,900
Common stock, diluted	73,798	68,260	59,452	65,029	50,475
Selected Cash Flow Data:					
Net cash provided by operating activities	$143,468	$133,328	$76,771	$101,087	$58,495
Net cash used in investing activities	(175,893)	(405,518)	(447,447)	(217,006)	(69,123)
Net cash provided by financing activities	36,758	271,275	370,475	115,210	12,017

	As of December 31,				
	2014	2013	2012	2011	2010
	(in thousands)				
Balance Sheet Data:					
Total assets	$1,455,101	$1,468,809	$1,364,130	$947,560	$760,523
Long term debt	775,961	736,671	563,865	170,000	127,900
Total liabilities	928,483	935,257	831,946	431,735	356,657
Stockholders' equity	526,618	533,552	532,184	515,825	403,866

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.

As of December 31, 2014, we estimated net proved reserves were approximately 74.2 MMBoe, of which approximately 45% were proved developed producing reserves and approximately 86% were oil. The standardized measure of our estimated net proved reserves as of December 31, 2014, was $833 million. 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.

In view of the current depressed oil and gas price environment, we have adopted an operating and financial plan for 2015 that holds production essentially flat, while preserving capital and paying down debt. We expect to fund our 2015 capital expenditures exclusively from internally generated cash flow. We also continue to explore alternative means to increase activity within our asset base including ongoing evaluation of opportunities in light of the commodity price environment and the evolving drilling, completion and operating cost structure. We also may enter into joint ventures to drill wells on the Company's acreage.

Outstanding indebtedness at December 31, 2014, consisted of $235 million in Revolving Credit Facility debt, $150 million under the Secured Term Loan Facility and $400 million of Senior Notes. As of December 31, 2014, our Revolving Credit Facility had a borrowing base of $330 million. We expect that this borrowing base will be reduced, perhaps significantly, at the next borrowing base redetermination, which is expected to occur on or about March 31, 2015. We will pursue such actions as are necessary to preserve our liquidity and to remain in compliance with the terms and conditions of our Revolving Credit Facility, Secured Term Loan Facility, and Senior Notes, including additional second lien borrowings, non-core asset sales, sales of other debt or equity securities, and other transactions.

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 result 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 2016. 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. 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 Permian Properties in 2011 and 2012 and Denbury’s interest in the Aneth Field Properties in 2012. Over that period of time, we have added reserves by initiating a complex CO_2 tertiary enhanced recovery project in Aneth Field and by drilling vertical, horizontal and slant-hole wells in our various operating areas. In a better product pricing environment, we will seek to add reserves through similar means.

We 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, 2014, we have estimated net proved reserves of approximately 40.5 MMBoe that were classified as proved developed non-producing and proved undeveloped, as compared to 25.7 MMBoe at December 31, 2013. An estimated 27.6 MMBoe, or 68%, of those reserves at year-end 2014 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. Approximately 21.1 MMBoe have been added as proved undeveloped, comprised of four CO_2 injection projects in the Aneth Field Properties. Additionally, the Permian and Powder River basin properties had active drilling programs in 2014, resulting in 1.7 MMBoe added to proved developed producing from successful drilling of non-proved locations. Furthermore, these successful wells created additional proved undeveloped offset locations carrying 6.0 MMBoe reserves.

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, rental equipment, 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. Volatility in commodity prices can also lead to changes in demand for drilling rigs, workover rigs, operating personnel and field supplies and services, which in turn can impact the costs of those goods and services.

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, 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 and Secured Term Loan 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 principles generally accepted in the United States ("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.

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 attempt to overcome this natural decline by developing existing properties, implementing secondary and tertiary recovery techniques and by acquiring more reserves than we produce. 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.

2015 Guidance

The following table summarizes our current financial and operational estimates for 2015.

Projected 2015 production	
Annual MBoe	4,380 - 4,745
Boe per day	12,000 - 13,000
On a revenue-basis:	
Oil	85%
Oil and NGL	88%

On a volume-weighted basis:	
Oil	71%
Oil and NGL	80%
Projected 2015 costs	
Lease operating expense ($ million)[1]	$88 - $98
General and administrative ($ million, after COPAS, before capitalized items)[1]	$25 - $29
Production and related taxes (% of production revenue)	12.5% - 13.0%
Depletion, depreciation and amortization ($ per Boe)	$29.00 - $30.00
Projected 2015 capital expenditures ($ million)	$45 - $50

(1) Excludes non-cash items.

2015 Capital Expenditures. As described in the above-table, Resolute expects to invest between $45 million and $50 million in 2015 in the plan, including completions, minimal facilities construction and upgrades, purchase of CO_2, leasing and other corporate capital. Approximately 42 percent of that capital budget will be spent in the Permian Basin, 36 percent in Aneth Field (including CO_2

purchases) and 22 percent in the Powder River Basin, leasing and other corporate capital. The Company expects to fund 2015 capital expenditures exclusively from internally generated cash flow.

Resolute will evaluate its capital expenditures in relation to its cash flow and may adjust its activity and capital spending levels based on changes in commodity prices, the cost of goods and services, production results and other considerations.

Please read "Quantitative and Qualitative Disclosures about Market Risk – Commodity Price Risk and Derivative Arrangements" which summarizes our derivative positions for 2015.

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, 2014, in comparison to results for the twelve months ended December 31, 2013 and 2012.

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 2014, 2013 and 2012.

	Twelve Months Ended December 31,		
	2014	2013	2012
Net Sales:			
Oil (MBbl)	3,488	3,499	2,773
Gas (MMcf)	5,023	4,565	3,567
NGL (MBbl)	320	207	41
Total sales (MBoe)	4,645	4,467	3,409
Average daily sales (Boe/d)	12,727	12,239	9,313
Revenue:			
Revenue from oil and gas activities	$329,371	$349,779	$258,268
Operating Expenses:			
Lease operating	$112,683	$103,276	$79,922
Production and ad valorem taxes	37,216	40,402	35,716
General and administrative	39,992	35,625	24,032
General and administrative (excluding non-cash compensation expense)	24,494	21,651	15,297
Depletion, depreciation, amortization and accretion	132,154	116,344	78,414
Impairment of proved oil and gas properties	120,000	188,000	—
Other Income (Expense):			
Interest expense	$(31,489)	$(29,302)	$(15,523)
Commodity derivative instruments gain (loss)	118,141	(15,336)	5,176
Income tax benefit (expense)	4,140	64,679	(11,881)
Average Sales Prices:			
Oil ($/Bbl)	$84.28	$91.75	$86.70
Gas ($/Mcf)	5.23	4.70	4.57
NGL ($/Bbl)	28.58	35.18	37.98

Average sales price ($/Boe, excluding commodity derivative settlements)	$70.90	$78.30	$75.77
Operating Expenses ($/Boe):			
Lease operating	$24.26	$23.12	$23.45
Production and ad valorem taxes	8.01	9.04	10.48
General and administrative	8.61	7.97	7.05
General and administrative (excluding non-cash compensation expense)	5.27	4.85	4.49
Depletion, depreciation, amortization and accretion	28.45	26.04	23.00

Year Ended December 31, 2014, Compared to the Year Ended December 31, 2013

Revenue. Revenue from oil and gas activities decreased to $329.4 million during 2014, from $349.8 million during 2013. The $20.4 million decrease in revenue was attributable to $34.4 million in commodity price decreases ($70.90 per Boe in 2014 versus $78.30 per Boe in 2013) offset by increased production of $14.0 million. Sales volumes increased 4% to 4,645 during 2014 as compared to 4,467 MBoe during 2013 primarily due to drilling activities during 2014.

Operating Expenses. Lease operating expenses increased to $112.7 million during 2014, from $103.3 million during 2013. The $9.4 million, or 9%, increase was primarily due to additional operating expenses associated with increased operational activity in the Permian Basin. On a unit of production basis, lease operating expense increased 5% to $24.26 per Boe in 2014 from $23.12 per Boe in 2013.

Production and ad valorem taxes decreased by 8% to $37.2 million during 2014, versus $40.4 million during 2013, mainly due to comparatively greater revenues generated in areas with lower tax rates. Production and ad valorem taxes were 11% of total revenue in 2014 and 12% in 2013.

General and administrative expenses increased to $40.0 million during 2014, as compared to $35.6 million during 2013. The $4.4 million, or 12%, increase resulted from additional personnel expense from short-term incentive compensation, as the Company met or exceeded its guidance metrics during 2014, offset by overhead billings and capitalized expense. Cash-based general and administrative expense was $24.5 million, or $5.27 per Boe in 2014, compared to $21.7 million, or $4.85 per Boe in 2013. Share-based compensation expense represented $15.5 million, or $3.34 per Boe, during 2014 and $14.0 million, or $3.13 per Boe, during 2013.

Depletion, depreciation, amortization and accretion expenses increased to $132.2 million during 2014, as compared to $116.3 million during 2013. The $15.9 million, or 14%, increase is principally attributable to an increase in the depletion, depreciation and amortization rate due to an increase in future development costs included in the 2014 amortization base and the 4% increase in 2014 production. On a per unit basis depreciation, amortization and accretion expenses increased to $28.45 per Boe in 2014 from $26.04 per Boe in 2013.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. We recorded a $120 million and $188 million non-cash impairment of the carrying value of our proved oil and gas properties at December 31, 2014 and 2013, respectively, as a result of the ceiling test limitation. The 2014 impairment resulted primarily from lower oil prices realized during the fourth quarter of 2014, while the 2013 impairment resulted primarily from the SEC “five year rule” for PUD properties. In addition, our estimate of proved reserves as of December 31, 2014 was based on a pricing methodology required by SEC rules. This commodity price assumption used in calculating our reserves significantly exceeds the current market price of oil and gas. Therefore it is likely that we will have substantial downward adjustments in our estimated proved reserves in the future if the current low commodity price environment persists.

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 2014 the gain on oil and gas commodity derivatives was $118.1 million. This amount included $123.1 million of mark-to-market gains on oil and gas derivatives offset by $5.0 million of derivative settlement losses. During 2013 the loss on oil and gas commodity derivatives totaled $15.3 million. This amount included $35.8 million of derivative settlement losses offset by $20.5 million of mark-to-market gains.

Interest expense was $31.5 million during 2014 as compared to $29.3 million during 2013. The $2.2 million, or 7%, increase is attributable to $1.5 million of increased interest expense due to increased levels of borrowings and $0.9 million of decreased capitalized interest due to lower unproved oil and gas property balances during 2014. The components of our interest expense are as follows (in thousands):

	Year Ended December 31,	
	2014	2013
8.50% senior notes	$34,000	$34,000
Revolving credit facility	10,196	8,671
Amortization of deferred financing costs and senior notes premium	2,337	2,481
Other, net	(104)	13
Capitalized interest	(14,940)	(15,863)
Total interest expense	$31,489	$29,302

Income Tax Benefit (Expense). Income tax benefit recognized during 2014 was $4.1 million, or 16% of the loss before income taxes, as compared to income tax benefit of $64.7 million, or 36% of the loss before income taxes in 2013. The decrease in the effective tax rate over 2013 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 $1 million non-current deferred tax asset at December 31, 2014, 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, 2013, Compared to the Year Ended December 31, 2012

Revenue. Revenue from oil and gas activities increased to $349.8 million during 2013, from $258.3 million during 2012. The $91.5 million increase in revenue was attributable to $80.2 million in increased production and $11.3 million in commodity price increases ($75.77 per Boe in 2012 versus $78.30 per Boe in 2013). Sales volumes in 2013 increased 31% as compared to 2012, from 3,409 MBoe to 4,467 MBoe, primarily due to wells associated with the Permian Acquisitions and drilling activities during 2013.

Operating Expenses. Lease operating expenses increased to $103.3 million during 2013, from $79.9 million during 2012. The $23.4 million, or 29%, increase was due to additional operating expenses associated with the Permian Acquisitions and increased operational activity in the Permian Basin, offset by decreased lease operating expenses related to our Wyoming Properties and properties divested in North Dakota. On a unit of production basis, lease operating expense decreased 1% from $23.45 per Boe in 2012 to $23.12 per Boe in 2013.

Production and ad valorem taxes increased by 13% to $40.4 million during 2013, versus $35.7 million during 2012, mainly due to the increase in production during 2013. Production and ad valorem taxes were 12% of total revenue in 2013 and 14% in 2012.

General and administrative expenses increased to $35.6 million during 2013, as compared to $24.0 million during 2012. The $11.6 million, or 48%, increase resulted from increases in salaries and burdens associated with expanded operations, share-based compensation expense, corporate overhead and professional services fees, offset by increased overhead billings and capitalized expense. Cash-based general and administrative expense was $21.7 million, or $4.85 per Boe in 2013, compared to $15.3 million, or $4.49 per Boe in 2012. Share-based compensation expense represented $14.0 million, or $3.13 per Boe, during 2013 and $8.7 million, or $2.56 per Boe, during 2012.

Depletion, depreciation, amortization and accretion expenses increased to $116.3 million during 2013, as compared to $78.4 million during 2012. The $37.9 million, or 48%, increase is principally due to a higher depletable base, higher finding costs and the 31% increase in production during 2013.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. We recorded a $188 million non-cash impairment of the carrying value of our proved oil and gas properties at December 31, 2013, as a result of the ceiling test limitation. No provision for impairment was recorded in 2012.

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 2013 the loss on oil and gas commodity derivatives was $15.3 million. This amount included $35.8 million of derivative settlements, including $10.7 million paid to restructure or terminate certain derivative contracts, offset by $20.5 million of mark-to-market gains on oil and gas derivatives. During 2012 the loss on oil and gas commodity derivatives totaled $5.2 million, including $22.9 million of derivative settlements, of which $3.4 million was related to partial terminations of certain derivative contracts, offset by $28.1 million of mark-to-market gains.

Interest expense was $29.3 million during 2013 as compared to $15.5 million during 2012. The $13.8 million, or 89%, increase is attributable to a partial year of interest expense related to the Senior Notes issuances in 2012 versus a full year of interest expense in 2013 and a higher average debt balance during 2013. The components of our interest expense are as follows (in thousands):

	Year Ended December 31,	
	2013	2012
8.50% senior notes	$34,000	$15,264
Revolving credit facility	8,671	3,220
Amortization of deferred financing costs and senior notes premium	2,481	1,691
Other, net	13	(1)
Capitalized interest	(15,863)	(4,651)
Total interest expense	$29,302	$15,523

Income Tax Benefit (Expense). Income tax benefit recognized during 2013 was $64.7 million, or 36% of loss before income taxes, as compared to income tax expense of $11.9 million, or 40% of income before income taxes in 2012. The decrease in the effective tax rate over 2012 is the result of the weighted change in tax jurisdictions in which we currently operate combined with 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 an $8.3 million current deferred tax asset at December 31, 2013, 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 Revolving Credit Facility, proceeds from the issuance of debt and equity securities and sales of oil and gas properties. For purposes of Management's Discussion and Analysis of Liquidity and Capital Resources, we have analyzed our cash flows and capital resources for the years ended December 31, 2014, 2013 and 2012.

	Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Cash provided by operating activities	$143,468	$133,328	$76,771
Cash used in investing activities	(175,893)	(405,518)	(447,447)
Cash provided by financing activities	36,758	271,275	370,475

Net cash provided by operating activities during 2014 was $143.5 million, as compared to $133.3 million during 2013 and $76.8 million during 2012. The increase in net cash provided by operating activities in 2014 over 2013 was primarily due to changes in working capital. The increase in 2013 over 2012 was primarily due to an increase in revenue from oil and gas activities and changes in working capital. In 2015, reflecting the current product pricing environment, we expect to limit our capital expenditures to cash flow generated by our operations.

Net cash used in investing activities was $175.9 million during 2014 as compared to $405.5 million during 2013 and $447.4 million during 2012. The primary investing activity in 2014 was cash used for capital expenditures of $183.6 million. Capital expenditures consisted primarily of $25.6 million in compression and facility and drilling projects in Aneth Field, $16.3 million in CO_2 acquisition, $122.9 million in drilling activities and infrastructure projects in the Permian Basin of west Texas and $18.5 million in drilling and completion activities in our Wyoming Properties. Capital divestitures included $6.6 million of proceeds from the sale of certain operated properties in the Bakken trend of North Dakota and $4.4 million of proceeds from the sale of certain interests in the Delaware basin. The primary investing activity for 2013 was cash used for capital expenditures of $519.7 million. Capital expenditures consisted of $258 million paid to acquire additional Permian Properties, $46.0 million in compression facility and drilling projects in Aneth field, $20.0 million in CO_2 acquisition, $135.1 million in drilling activities and infrastructure projects in the Permian Basin, $13.2 million in additional acreage acquisition in the Permian Basin, $34.6 million in drilling and completion activities in the Bakken trend of North Dakota and $12.5 million in drilling and recompletion activities in our Wyoming properties. Capital divestitures include $50.2 million received from NNOGC for the sale of certain working interests in the Aneth Field Properties, $70.1 million of proceeds from the sale of certain properties in the Bakken trend of North Dakota and $1.0 million for the sale of certain working interests in other Permian properties.

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 additional 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. Capital divestitures include $49.5 million received from NNOGC for the sale of certain working interests in the Aneth Field Properties. A portion of these capital costs are accrued and not paid at period end.

Net cash provided by financing activities was $36.8 million in 2014 as compared to $271.3 million in 2013 and $370.5 million in 2012. The primary financing activity in 2014 was $139.5 million in net proceeds from the issuance of the Secured Term Loan Facility and $100 million in net repayment of borrowings under the Revolving Credit Facility. The primary financing activities in 2013 were net borrowings of $173.0 million under the Revolving Credit Facility and $101.8 million in net proceeds received from the issuance of common stock. 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 Revolving Credit Facility and $10.0 million paid to retire a portion of our warrants.

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 Revolving Credit Facility (if available), issuances of additional second lien debt or other debt or equity securities or from other sources, such as asset sales. We have in place an effective shelf registration statement, with a remaining capacity of $394 million; however our ability to access this capacity may be substantially limited by applicable shelf eligibility rules. 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 Revolving Credit Facility, Secured Term Loan Facility, or 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.

Our Revolving Credit Facility and our Secured Term Loan Facility require us to enter into derivative agreements covering at least 70% of our anticipated production from proved properties on a rolling twenty four month basis, but prohibit 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 Revolving Credit Facility.

We plan to continue our practice of hedging a significant portion of our production through the use of various commodity derivative transactions. Our existing derivative transactions have not been designated 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 Revolving Credit Facility is with a syndicate of banks led by Wells Fargo Bank, National Association, as Administrative Agent, and Bank of Montreal, as Syndication Agent with Resolute as the borrower. The Revolving 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. We expect that the current borrowing base of $330 million will be reduced, perhaps significantly, at the next borrowing base redetermination, which will be effective on or about March 31, 2015. Under certain circumstances, either the Company or the lenders may request an interim redetermination.

In March 2013 we entered into the Sixth Amendment, which among other things, also extended the maturity date of the Revolving Credit Facility from April 2017 to March 2018. On March 7, 2014, we entered into the Ninth Amendment to the amended and restated Revolving Credit Facility which redefined and adjusted the Maximum Leverage Ratio to (a) 4.90:1.00 for the fiscal quarters ending March 31, 2014, and June 30, 2014, (b) 4.75:1.00 for the fiscal quarters ending September 30, 2014, and December 31, 2014, and (c) 4.00:1.00 for all quarters thereafter. The Ninth Amendment also provided that as of the last day of each fiscal quarter in 2014 the ratio of senior secured debt as of such date to Adjusted EBITDA as defined in the Revolving Credit Facility for the four quarter period ending on such date may not exceed 2.75:1.00.

In December 2014 we entered into the Eleventh Amendment to the amended and restated Revolving Credit Facility agreement. In connection with the Eleventh Amendment, the borrowing base was set at $330 million and certain other amendments were made, including eliminating the total debt-to-EBITDA covenant and conforming the covenant package in the Revolving Credit Facility to that of the Secured Term Loan Facility. The covenants require, among other things, maintenance of certain ratios, measured on a quarterly basis, as follows: (i) secured debt to EBITDA of no more than 3.5 to 1.0, (ii) PV-10 of total proved reserves to total secured debt of at least 1.1 to 1.0, rising over time to 1.5 to 1.0, and (iii) PV-10 of proved developed reserves to total secured debt of at least 1.0 to 1.0. Our Revolving Credit Facility and our Secured Term Loan Facility also require us to enter into derivative agreements covering at least 70% of our anticipated production from proved properties on a rolling twenty four month basis, but prohibit 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 Revolving Credit Facility.

Each base rate borrowing under the Revolving 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 Offered Rate ("LIBOR") 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.

As of December 31, 2014, outstanding borrowings were $235 million under the borrowing base of $330 million. The borrowing base availability is reduced by $3.1 million in conjunction with letters of credit issued to vendors at December 31, 2014. 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. However, should the borrowing base be set at a level below the outstanding balance, we would be required to eliminate that excess over the 120 days following that determination. The Revolving 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, Resolute Wyoming, Inc. and Resolute Natural Resources Southwest, LLC, which are wholly-owned subsidiaries of the Company.

As of December 31, 2014, the weighted average interest rate on the outstanding balance under the Credit Facility was 2.17%. 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 customary 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, 2014.

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.

Secured Term Loan Agreement

On December 30, 2014, we and certain of our subsidiaries, as guarantors, entered into a second lien Secured Term Loan Agreement with Bank of Montreal, as administrative agent, and the lenders party thereto, pursuant to which we borrowed $150 million. Funding of the Secured Term Loan Facility occurred on December 31, 2014. The Secured Term Loan Facility will mature on the date that is six months after the maturity of our existing Revolving Credit Facility, but in no event later than November 1, 2019.

Net proceeds from the Secured Term Loan Facility, approximately $135 million after payment of transaction-related fees, expenses and discounts, were used to repay outstanding amounts under the Revolving Credit Facility.

Obligations under the Secured Term Loan Facility are guaranteed by certain of our subsidiaries and secured by second priority liens on substantially all of our assets and our subsidiaries that serve as collateral under the Revolving Credit Facility.

Borrowings under the Secured Term Loan Facility will bear interest at adjusted LIBOR plus 10%, with a 1% LIBOR floor. The covenants in the Secured Term Loan Facility require, among other things, maintenance of certain ratios, measured on a quarterly basis, as follows: (i) secured debt to EBITDA of no more than 3.5 to 1.0, (ii) PV-10 of total proved reserves to total secured debt of at least 1.1 to 1.0, rising over time to 1.5 to 1.0, and (iii) PV-10 of proved developed reserves to total secured debt of at least 1.0 to 1.0. In addition, the Secured Term Loan facility contains certain covenants relating to commodity price hedging described above under "Revolving Credit facility."

We may prepay all or a portion of the Secured Term Loan Facility at any time. The Secured Term Loan Facility is subject to mandatory prepayments of 75% of the net cash proceeds from asset sales, subject to a limited right to reinvest proceeds in oil and gas activities. Prepayments made out of proceeds from asset sales are not subject to prepayment premiums. Mandatory repayments are required of 100% of the net cash proceeds of certain debt or equity issuances. Such prepayments are subject to a premium of between 10% declining to 2% during the first 36 months after closing. To the extent not otherwise achieved, aggregate repayments that substantially pay off principal amounts under the Secured Term Loan Facility shall include an additional payment sufficient to ensure that the lenders achieve a 1.25 to 1.0 minimum multiple of their invested capital.

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 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.

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. In March 2013, the Company registered the Senior Notes with the Securities and Exchange Commission by filing an amendment to the registration statement on Form S-4 enabling holders of the Senior Notes to exchange the privately placed Notes for publically registered Notes with substantially identical terms. 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, 2014.

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 are party to any options on non-financial assets.

Contractual Obligations

We had the following contractual obligations and commitments for the next five years as of December 31, 2014:

	Less than 1 year	1-3 Years	3–5 Years	More Than 5 Years	Total [6]
	(in thousands)				
Obligations:					
Term loans and related interest	$50,500	$101,000	$230,375	$417,000	$798,875
Revolving credit facility [1]	—	—	235,000	—	235,000
Office and equipment leases	1,525	3,464	2,811	3,138	10,938
Operating equipment leases [2]	2,094	3,110	245	—	5,449
Vehicle leases	1,220	1,035	82	—	2,337
ExxonMobil escrow agreement [3]	1,638	2,332	1,451	10,762	16,183
Construction purchase obligations [4]	3,381	—	—	—	3,381
CO_2 purchases [5]	13,499	12,969	—	—	26,468
Total	$73,857	$123,910	$469,964	$430,900	$1,098,631

1) Represents the outstanding principal amount under our Revolving Credit Facility. This table does not include future commitment fees, interest expense or other fees because the Revolving 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, 2014, 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, 2014.
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.

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.

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 commodity 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. Consequently, we recognize gains and losses in earnings rather than deferring such amounts in other comprehensive income as would be 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 mark-to-market 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.

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 Revolving Credit Agreement and our Secured Term Loan Agreement the form of derivative instruments to be entered into is at our discretion, but require us to enter into derivative agreements covering at least 70% of our anticipated production from proved properties on a rolling twenty four month basis 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. Resolute is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above. All counterparties are lenders under our Revolving Credit Facility. Accordingly, Resolute is not required to provide any credit support to its counterparties other than cross collateralization with the properties securing the Credit Facility. Resolute’s derivative contracts are documented with industry standard contracts known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. Master Agreement (“ISDA”). Typical terms for each ISDA include credit support requirements, cross default provisions, termination events, and set-off provisions. Resolute has set-off provisions with its lenders that, in the event of counterparty default, allow Resolute to set-off amounts owed under the Credit Facility or other general obligations against amounts owed for derivative contract liabilities.

Our management has determined that the benefit of cash flow hedge accounting, which may allow for our derivative instruments to be reflected as cash flow hedges in other comprehensive income, is not commensurate with the administrative burden required to support that treatment.

Derivative instruments are recognized on the balance sheet as either assets or liabilities measured at fair value. We mark our derivative instruments to fair value on the consolidated balance sheets and recognize the changes in fair market value in earnings. As of December 31, 2014, the fair value of our commodity derivatives was a net asset of $112.6 million.

The following table represents our commodity swap contracts as of December 31, 2014:

Oil (NYMEX WTI)	Gas (NYMEX Henry Hub)

Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	Fair Value of Asset (Liability) (in thousands)	MMBtu per Day	Weighted Average Swap Price per MMBtu	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2015	5,600	$ 86.80	$ 60,937	12,600	$ 3.635	$ 1,449
Jan – Dec 2016	6,500	$ 80.42	$ 39,799	—	$ —	$ —

The following table represents our two-way commodity collar contracts as of December 31, 2014:

	Oil (NYMEX WTI)			
Remaining Term	Bbl per Day	Weighted Average Floor Price per Bbl	Weighted Average Ceiling Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2015	1,000	$ 84.17	$ 92.10	$ 10,036

The following table represents our three-way gas collar contracts as of December 31, 2014:

	Gas (NYMEX Henry Hub)				
Remaining Term	MMBtu per Day	Weighted Average Short Put Price per MMBtu	Weighted Average Floor Price per MMBtu	Weighted Average Ceiling Price per MMBtu	Fair Value of Asset (Liability) (in thousands)
Jan – Mar 2015	5,000	$ 3.75	$ 4.50	$ 5.55	$ 331

Interest Rate Risk

At December 31, 2014, we had $235 million and $150 million of outstanding debt under the Revolving Credit Facility and Secured Term Loan Facility, respectively. Interest is calculated under the terms of the agreements based on a LIBOR spread. A 10% increase in LIBOR would result in an estimated $0.1 million increase in annual interest expense. We do not currently have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

Credit Risk and Contingent Features in Derivative Instruments

We are exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above. All counterparties are also lenders under our Revolving Credit Facility. For these contracts, we are not required to provide any credit support to our counterparties other than cross collateralization with the properties securing the Revolving Credit Facility. Our derivative contracts are documented with industry standard ISDA contracts . Typical terms for the ISDAs include credit support requirements, cross default provisions, termination events, and set-off provisions. We have set-off provisions with our Revolving Credit Facility lenders that, in the event of counterparty default, allow us to set-off amounts owed under the Revolving Credit Facility or other general obligations against amounts owed for derivative contract liabilities.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item is included in “Item 15. Exhibits, Financial Statement Schedules”.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Attached as exhibits to this report are certifications of our CEO and CFO required pursuant to Rule 13a-14 under the Exchange Act. This section includes information concerning the controls and procedures evaluation referred to in the certifications. Included in this report is the report of KPMG LLP, our independent registered public accounting firm, regarding its audit of our internal control over financial reporting. This section should be read in conjunction with the certifications and the KPMG LLP report for a more complete understanding of the topics presented.

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of December 31, 2014. This evaluation was conducted under the supervision and with the participation of management, including our CEO and CFO. Based on this evaluation, our CEO and CFO have concluded that as of December 31, 2014, our disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified by the rules and forms of the SEC. We also concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our CEO and CFO, to allow timely decisions regarding disclosure.

Management’s Annual Report on Internal Control over Financial Reporting. Management is responsible for establishing and maintaining adequate internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). Management assessed our internal control over financial reporting as of December 31, 2014, and has concluded that the Company maintained effective internal control over financial reporting as of December 31, 2014. This assessment was based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Changes in Internal Control over Financial Reporting. There have been no significant changes in our internal control over financial reporting during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2015 annual stockholders’ meeting and is incorporated by reference in this report.

ITEM 11.