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

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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:			