Resolute Energy Corp
Form 10-K
March 13, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

OR

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

Commission File No. 001-34464

RESOLUTE ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

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

(Address of principal executive offices) (Zip Code)

(303) 534-4600

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Exchange on Which Registered
Common Stock, par value $0.0001 per share	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 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.

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
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

The aggregate market value of registrant's common stock held by non-affiliates on June 30, 2016, computed by reference to the price at which the common stock was last sold as posted on the New York Stock Exchange, was $42.4 million.

As of February 28, 2017, 22,437,470 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 2017 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, the anticipated closing date and expected benefits of the Delaware Basin acquisitions, our production and cost guidance for 2017; anticipated capital expenditures in 2017 and the sources of such funding; availability of alternative oil purchase markets and oil takeaway systems; 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 the disposition of our Aneth Field properties, joint ventures and asset sales; liquidity and availability of capital including projections of free cash flow; additional future potential full cost ceiling impairments; future borrowing base adjustments and the effect thereof; future production, reserve growth and decline rates; 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, the rates of return on our acreage and projects; the prospectivity of our properties and acreage; and the anticipated accounting treatment of various activities. 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, although not exclusively, 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:

- our ability to consummate and to realize the expected benefits from the interests acquired in the Delaware Basin acquisitions;
- volatility of oil and gas prices, including extended periods of depressed 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 operations and other development 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, the senior notes and any additional indebtedness we may incur;
- constraints imposed on our business and operations by our revolving credit facility and senior notes may limit our ability to execute our business strategy;
- future write downs of reserves and the carrying value of our oil and gas properties;
- acquisitions and other business opportunities (or 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;
- our future cash flow, liquidity and financial position;
- the success of our business and financial strategy, derivative strategies and plans;
- the success of the development plan for and production from our oil and gas properties;
- risks associated with rising interest rates;
- 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;
- the completion, timing and success of drilling on our 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;
- 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 timing and amount of future production of oil and gas;
- the ability to sell or otherwise monetize assets, including our Aneth Field assets, at values and on terms that are advantageous to us;
- 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 third party-owned water sourcing, gathering and disposal, oil gathering and 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 relationship with the local communities in the areas where we operate;
- the availability of water and our ability to adequately treat and dispose of water while and after drilling and completing wells;
- regulation of waste water injection intended to address seismic activity;
- the concentration of our producing properties in a limited number of geographic areas;
- potential changes to regulations affecting derivatives instruments;
- environmental liabilities under existing or future laws and regulations;
- the impact of climate change regulations on oil and gas production and demand;
- anticipated CO_2 supply, which is currently sourced exclusively from Kinder Morgan CO_2 Company, L.P. under a contract with take or pay obligations;
- the effectiveness and results of our CO_2 flood program at Aneth Field;
- potential changes in income tax deduction and credits currently available to the oil and gas industry;
- 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 and failure to keep pace with technological development;
- actions, announcements and other developments in OPEC and in other oil and gas producing countries;
- risks relating to our joint interest partners' and other counterparties' inability to fulfill their contractual commitments;
- loss of senior management or key technical personnel;
- the impact of long-term incentive programs, including performance-based awards and stock appreciation rights;
- timing of issuance of permits and rights of way, including the effects of any government shut-downs;
- potential power supply limitations in the electrical infrastructure serving our operations;
- 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;
- cybersecurity risks;
- the risk of a transaction that could trigger a change of control under our debt agreements;
- risks related to our common stock, potential declines in stock prices and potential future 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.

SEC rules prohibit us from including resource estimates in our public filings with the 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.

Production rates, including 24-hour peak IP rates, 30-day peak IP rates, 90-day peak IP rates, 120-day peak IP rates and 150-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. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rate are 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. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease line offsets. Standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,500 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.

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

TABLE OF CONTENTS

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 the Delaware Basin in west Texas (the "Permian Properties" or "Permian Basin Properties") and Aneth Field located in the Paradox Basin in southeast Utah (the "Aneth Field Properties" or "Aneth Field"). Our development activity is focused on our 20,000 gross (16,400 net) operated acreage position in what we believe to be the core of the Wolfcamp horizontal play in northern Reeves County, Texas. Our corporate strategy is to drive organic growth in production, cash flow and reserves through development of our Reeves County acreage and opportunistic bolt-on acquisitions in the Delaware Basin while continuing to focus on improving margins in our Paradox Basin properties while de-risking certain future growth projects through selectively targeted capital investment.

During 2016 oil sales comprised approximately 90% of revenue, and our December 31, 2016, estimated net proved reserves were approximately 60.3 million barrels of oil equivalent ("MMBoe"), of which approximately 62% and 59% were proved developed reserves and proved developed producing reserves ("PDP"), respectively. Approximately 73% of our estimated net proved reserves were oil and approximately 85% were oil and natural gas liquids ("NGL"). The December 31, 2016, pre-tax present value discounted at 10% ("PV-10") of our net proved reserves and the standardized measure of our estimated net proved reserves were $344 million. For additional information about the calculation of our PV-10 and standardized measure, please read "Business and Properties — Estimated Net Proved Reserves."

For 2016, our Board of Directors approved a capital budget of between $115 million and $135 million, primarily focused on continuing horizontal development of our Delaware Basin Wolfcamp resource base in Reeves County, Texas, (the "Reeves County Assets") where we planned to drill and complete a total of nine wells. Capital spending in Aneth Field was limited to acquisition of CO_2, upgrades in electrical infrastructure and basic field maintenance. The drilling success achieved in our Reeves County Assets during the first half of 2016 led us to expand our 2016 drilling program by adding five additional wells (for a total of fourteen wells during 2016). Because these additional wells were drilled in the third and fourth quarters, they did not materially contribute to aggregate 2016 production. However, these wells added to our 2016 exit production rate and will provide momentum to our 2017 production volumes. Our 2016 capital plan reflected our intention to make investments in assets that are accretive to net asset value at current prices and to grow proved reserves and production that will benefit the Company as we move through 2017.

For 2017, we expect to incur capital expenditures of $210 to $240 million, primarily focused on following our successful 2016 performance in the Delaware Basin with a two rig drilling program spudding 22 gross wells. We expect the 2017 program to accomplish a number of important initiatives for the Company. We will further delineate our development inventory as we drill wells across our acreage block, conduct multiple spacing tests and complete wells in multiple landing zones in the Wolfcamp A as well as in the Wolfcamp B. The success of this program will help confirm the more than 370 Wolfcamp A and B development locations we believe exist in our Mustang and Appaloosa project areas. We also expect that substantially all of our acreage will be held by production by the end of

2017.

We expect to outspend our cash flows from operations during 2017. A deterioration of commodity prices from current levels could negatively impact our results of operations, financial condition and future development plans. We may decrease our 2017 capital investment forecast during the year as a result of, among other things, a decline in commodity prices, drilling results, cost increases, or unfavorable changes in our borrowing capacity. We may also change our capital expenditure plan depending upon our ability to consummate the Delaware Basin Orla Acquisition (defined below) and/or the potential divestiture of our Aneth Field assets described below.

On February 22, 2017 we closed on the sale of our Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million, subject to customary purchase price adjustments (the “New Mexico Sale”). The effective date of this sale is October 1, 2016. The proceeds of the sale will be used for general corporate purposes.

On March 3, 2017, Resolute Natural Resources Southwest, LLC (“Buyer”), a wholly-owned subsidiary of the Company, entered into a Purchase and Sale Agreement (the “Purchase Agreement”) with undisclosed private sellers (“Sellers”) pursuant to which Buyer agreed to acquire certain producing and undeveloped oil and gas properties in the Delaware Basin in Reeves County, Texas (the "Delaware Basin Orla Acquisition").

Consideration for the acquisition will be $160 million in cash, subject to customary purchase price adjustments. The closing of the acquisition is expected to occur on or about May 15, 2017, and is subject to the satisfaction or waiver of certain customary conditions, including the material accuracy of the representations and warranties of Buyer and Sellers, and performance of covenants. The Delaware Basin Orla Acquisition has an effective date of May 1, 2017. The Purchase Agreement contains terms and conditions customary to transactions of this type. Subject to the right of Buyer to be indemnified for certain liabilities for a limited period of time and for breaches of representations, warranties and covenants, Buyer will assume substantially all liabilities associated with the acquired properties. The Purchase Agreement also contains certain customary termination rights for each of Buyer and Sellers.

The properties to be acquired include approximately 4,600 net acres in Reeves County, Texas, consisting of 2,187 net acres adjacent to the Company's existing operating area in Reeves County and 2,405 net acres in southern Reeves County. In addition, the Company will acquire interests in (i) two operated 4,500 foot lateral horizontal Wolfcamp wells that currently produce approximately 800 net Boe per day, (ii) six operated drilled but uncompleted Wolfcamp wells, four of which have lateral lengths of approximately 4,500 feet and two with approximately 7,500 foot laterals; and (iii) one non-operated 10,000 foot lateral Wolfcamp A well that is currently drilling.

To complete our repositioning as a pure-play Delaware Basin company, Resolute's board of directors has directed management to explore and take preparatory steps toward a disposition of the Company's Aneth Field assets. The potential disposition of Aneth Field, if consummated, would provide meaningful additional capital to Resolute. This capital can be deployed either to our Delaware Basin drilling program where we see our highest rates of return or as a component of the optimal long-term financing for the Delaware Basin Orla Acquisition.

Business Strategies

The key elements of our business strategy include:

Organically Grow Production, Cash Flow and Reserves. Our primary business strategy is to generate growth in production, cash flow and reserves through organic development of the Wolfcamp formation in our Reeves County Assets in the Delaware Basin. For 2017 our board of directors approved a two rig drilling program spudding 22 gross wells. Upon closing the Delaware Basin Orla Acquisition, we plan to complete six drilled but uncompleted wells on the acquired properties sequentially and will evaluate adding a third rig in the second half of 2017 to accelerate the development of the acquired properties.

Pursue Acquisition Opportunities in Delaware Basin. We will continue to seek out attractive opportunities to expand our acreage and inventory of development locations through strategic acquisitions relying on our more than five year operating history in the Delaware Basin and our strong technical team to identify the best opportunities. The Delaware Basin Firewheel Acquisition (defined below) and the recently announced Delaware Basin Orla Acquisition represent examples of such opportunities.

Focus on the Profitability of Aneth Field. We will continue to focus on cost control and production maintenance in our Aneth Field Properties. In addition, we expect to develop a strategy to de risk additional growth opportunities in the field. To complete our repositioning as a pure-play Delaware Basin company, Resolute's board of directors has directed management to explore and take preparatory steps toward a disposition of the Company's Aneth Field assets.

Improve Corporate Profitability. We will continue to focus on improving the profitability of the Company through a multi pronged strategy, including, (a) improved unit operating costs resulting from increased production in lower cost areas and divestitures of higher cost properties, (b) improved well economics as we continue to focus on drilling efficiencies, shift to infill drilling which leverages existing infrastructure and realize economies from a larger sustained drilling program, and (c) focus on improving overhead expenses per unit of production and optimizing efficiency within our corporate organization.

Divest of Non Core Assets. We entered into a Purchase and Sale Agreement to sell our producing properties in southeast New Mexico for a purchase price of $14.5 million. The closing of the sale occurred on February 22, 2017, effective as of October 1, 2016. These non core assets did not contribute to our organic growth strategy. The net proceeds were used to reduce leverage, which we expect will ultimately enable us to accelerate drilling in Reeves County. We intend to continue our evaluation and execution of additional non-core asset sales, when and as appropriate.

Strategically Use Equity to Manage Leverage. The Delaware Basin Firewheel Acquisition (defined below) was financed with a significant issuance of both common and convertible preferred equity. With respect to the recently announced Delaware Basin Orla Acquisition, we anticipate that the ultimate financing may have components of long-term debt and equity, although we are still evaluating the optimal financing structure, particularly in light of our recent decision to explore a potential divestiture of Aneth Field. As we look at additional acquisition opportunities, we will continue to consider the possibility of utilizing equity as consideration or a financing component.

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our 2017 and longer term business strategies, including:

Multi year Portfolio of Significant Organic Drilling and Development Opportunities in One of the Premier U.S. Oil and Gas Producing Basins. We have a significant inventory of drilling and development locations in Reeves County, Texas, in what we believe to be the core of the Delaware Basin portion of the Permian Basin. This part of the Delaware Basin is a premier U.S. onshore oil and gas resource. Based only on zones that have established production from our nearby horizontal wells, we have identified a substantial inventory of more than 370 gross horizontal well locations in the Wolfcamp A and B. Upon closing the Delaware Basin Orla Acquisition, we expect that inventory to increase substantially. We believe that this inventory will allow us to grow our reserves and production, while generating attractive rates of return at current commodity price levels and our current projected cost structure. Recent developments in the area lead us to conclude that we may be able to increase our drilling opportunity inventory through tighter spacing and increasing the number of productive horizons above and below existing producing zones.

Operational Staff with Deep Expertise; Operating Control of Our Properties. Our operating and technical staff has significant experience in the drilling, completing and operating of horizontal wells. This expertise has led to cost and production enhancements, particularly in Reeves County. The work of our drilling team has led to reductions in drilling days and larger completion designs which we believe ultimately result in more productive and economic wells. Because we are the operator of substantially all of our properties we have the ability to more directly control the timing, scope and costs of our activity. Further, operatorship of our Reeves County Assets is secured for the foreseeable future, as approximately 77% of the gross acreage is held by production.

Stable Long lived Oil Production from Aneth Field. Our field staff has been operating Aneth Field since before its purchase by the Company. Aneth Field has exhibited a long, shallow decline. With only modest capital expenditures, production has remained essentially flat over the last eight quarters. Additionally, our operating teams have found ways to reduce operating costs more than 25% since the second quarter of 2014. Because Aneth Field is held by production, it can serve as a long term source of production and cash flow.

Summary Reserve Information

The following table presents summary information related to our estimated net proved reserves that are derived from our December 31, 2016, 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, 2016 (MMBoe)	
	ProvedProved	2016 Net Daily

	Developed Producing	Developed Non-Producing	Proved Undeveloped	Total Proved	Production (Boe per day)
Aneth Field Properties	19.9	2.4	2.1	24.4	6,161
Permian Properties	15.4	—	20.5	35.9	7,996
Total	35.3	2.4	22.6	60.3	14,157

Future operating costs ($ millions)	$756.6
Future production taxes ($ millions)	175.4
Future capital costs ($ millions)	287.9
Future operating costs ($/Boe)	12.6
Future production taxes ($/Boe)	2.9
Future capital costs ($/Boe)	11.5

Description of Properties

Permian Basin Properties

As of December 31, 2016, we had interests in approximately 23,900 gross (20,000 net) acres in the Permian Basin of Texas and southeast New Mexico. Approximately 35.9 MMBoe of proved reserves are associated with these assets as of December 31, 2016.

During the year, we completed 14 gross (12.0 net) wells in the Permian Basin Properties and had 86 gross (76.7 net) producing wells at year-end 2016. As of December 31, 2016, we were in the process of drilling 1 gross (1.0 net) well and had 1 gross (1.0 net) well awaiting completion operations. During 2016, average net daily production from the Permian Basin Properties was 7,996 equivalent barrels of oil ("Boe") and was 77% liquids. See "Business and Properties – Marketing and Customers" for more information on how production from this area is sold.

Delaware Basin Project. The Delaware Basin is our principal project area and includes approximately 20,000 gross (16,400 net) acres. The primary objective in this area is the Wolfcamp formation, particularly the Wolfcamp A and B subzones. Near our project area other operators are also developing the Wolfcamp C and D subzones, the X/Y and the Third Bone Spring formation. Based on drilling activity to date, approximately 77% of the gross acreage is held by production. Approximately 35.4 MMBoe of proved reserves are associated with these assets as of December 31, 2016. We believe that growth potential exists from more than 370 gross prospective wells targeting upper Wolfcamp A, lower Wolfcamp A and upper Wolfcamp B formations, which includes twenty proved undeveloped locations. We believe that significant additional opportunity exists from reduced spacing as well as additional subzones. For 2017, the Board has approved a two rig drilling program spudding 22 gross wells (provided that this program does not take into account additional potential drilling following the anticipated consummation of the Delaware Basin Orla Acquisition).

Divestiture of Southeast New Mexico Properties in the Permian Basin. In February 2017 we sold our Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million, subject to customary purchase price adjustments (the "New Mexico Sale"). The closing of the New Mexico Sale occurred on February 22, 2017, with an effective date of October 1, 2016. The proceeds of the sale will be used for general corporate purposes.

Acquisition of Reeves County Properties in the Delaware Basin. In October 2016 we acquired certain Reeves County interests in the Delaware Basin, for consideration consisting of $90 million in cash and 2,114,523 shares of common stock of the Company, par value $0.0001 per share, issued to Firewheel Energy, LLC ("Firewheel") upon the closing of the purchase of the Firewheel properties (the "Firewheel Properties") in the Delaware Basin (the "Delaware Basin Firewheel Acquisition").

Divestiture of Midstream Assets in the Delaware Basin. In July 2016 Resolute Natural Resources Southwest, LLC ("Resolute Southwest"), a wholly owned subsidiary of Resolute, entered into a definitive Purchase and Sale Agreement (the "Mustang Agreement") with Caprock Permian Processing LLC and Caprock Field Services LLC, as buyers (collectively, "Caprock") pursuant to which Resolute Southwest and a then existing minority interest holder (collectively, the "Sellers") agreed to sell certain gas gathering and produced water handling and disposal systems owned by them in the Mustang project area in Reeves County, Texas, ("Mustang") for a cash payment of $35 million, plus certain earn-out payments described below.

In July 2016 Resolute Southwest also entered into a definitive Purchase and Sale Agreement (the "Appaloosa Agreement") with Caprock, pursuant to which Resolute Southwest agreed to sell certain gas gathering and produced water handling and disposal systems owned by Resolute Southwest in the Appaloosa project area in Reeves County, Texas, ("Appaloosa") for a cash payment of

$15 million, plus certain earn-out payments described below.

In August 2016 Resolute Southwest closed the transactions contemplated by the Mustang Agreement and the Appaloosa

Agreement. Resolute Southwest received aggregate consideration of approximately $36 million (including earn-out payments earned as of the closing), of which approximately $2 million was placed in an escrow account for a period of time to secure Resolute's indemnity obligations under the Mustang Agreement and the Appaloosa Agreement. As the sale did not significantly alter the relationship between capital costs and proved reserves, no gain or loss was recognized.

The net proceeds of the midstream sale were used to repay amounts outstanding under our Revolving Credit Facility (as defined below) and for general corporate purposes.

In July 2016, in connection with the Appaloosa Agreement and the Mustang Agreement, Resolute Southwest also entered into a definitive Earn-out Agreement (the "Earn-out Agreement"), pursuant to which Resolute Southwest will be entitled to receive certain earn-out payments based on drilling and completion activity in Appaloosa and Mustang through 2020 that will deliver gas and produced water into the system. Earn-out payments for each qualifying well will vary depending on the lateral length of the well and the year in which the well is drilled and completed. On March 10, 2017, the Earn-out Agreement was amended by the parties to provide for an increase in earn-out payments for wells drilled and completed in 2017. Earn-out payments are contingent on future drilling, and therefore will be recognized when received.

In connection with the closing of the transactions contemplated by the Appaloosa Agreement and the Mustang Agreement, Resolute Southwest entered into fifteen year commercial agreements with Caprock for gas gathering and processing services and water handling and disposal services for all current and future gas and water produced by Resolute Southwest in Mustang and Appaloosa in exchange for customary fees based on the volume of gas and water produced and delivered. Resolute Southwest has agreed to dedicate and deliver all gas and water produced from its acreage in Mustang and Appaloosa to Caprock for gathering, processing, compression and disposal services for a term of fifteen years.

Divestiture of Properties in the Midland Basin. In December 2015 we sold our Gardendale properties in the Midland Basin in Midland and Ector Counties, Texas, for approximately $172 million. In May 2015 we sold our Howard and Martin County properties in the Permian Basin for approximately $42 million.

Aneth Field Properties

Aneth Field, a giant legacy oil field in southeast Utah, holds 41% of our net proved reserves as of December 31, 2016, and accounted for 44% of our production during 2016, averaging 6,161 Boe per day, of which 95% was oil. We own a majority of the working interests in, and are the operator of, three federal production units covering approximately 44,000 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 62.4%, 67.5% and 58.6%, respectively, at December 31, 2016. We had interests in and operated 376 gross (238.5 net) producing wells and 324 gross (204.4 net) active water and CO_2 injection wells.

Aneth Field was discovered in 1956 by Texaco and has produced approximately 448 million barrels ("MMBbl") of oil to date. Aneth Field covers a single geologic structure with production coming from Pennsylvanian age Ismay and Desert Creek formations. 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 ("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 96 producing wells in the first four 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 171% from 2006. During 2017 CO_2 injection will continue into the currently developed patterns of Phase 1, 2, 3 and 4.

The existing Aneth Unit CO_2 flood expansions and the projected CO_2 flood expansion in the Ratherford Unit are in the same field and producing formation as the existing McElmo Creek Unit CO_2 project. Initially, oil and gas reserves associated with expansions are classified as proved undeveloped ("PUD"). Following installation of the necessary infrastructure, these CO_2-related reserves are reclassified as proved developed non-producing ("PDNP"). Once a response is exhibited at a producing well, the tertiary reserves associated with that well are then reclassified to proved developed producing ("PDP").

We believe significant opportunity exists to increase production from existing proved reserves. 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. In the Ratherford Unit, we have two potential CO_2 flood projects, one targeting both the Desert Creek I and II zones and a second targeting primarily the Desert Creek I zone. In Aneth Field at December 31, 2016, we had estimated net proved reserves of 2.4 MMBoe classified as PDNP and 2.1 MMBoe classified as PUD. These reserves are largely comprised of newly identified compression and deepening projects.

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. Projects in 2017 will be focused on testing these concepts for potential development.

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, 2016, we have a credit of $0.2 million to be applied to future CO_2 purchases. 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 41 degrees. The field is connected by pipeline to a refinery located near Gallup, New Mexico, that is owned and operated by Western Refining Southwest, Inc., a subsidiary of Western Refining Inc. ("Western"). Western currently purchases all of the non-royalty oil production of Resolute and NNOGC from Aneth Field under a purchase agreement initially entered into in July 2014. On December 31, 2014, the Company entered into an amendment to the agreement, 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 extended the term of the agreement until March 31, 2015, and provided that the term would continue thereafter on a month-to-month basis until terminated by a party with ninety days prior notice. On December 8, 2015, the Company entered into a second amendment to the agreement, which provided for a reduction of the differential to $7.50 per barrel of oil. On May 9, 2016, the Company entered into a third amendment to the agreement which provided that Resolute and NNOGC will receive a price equal to NYMEX oil price minus a differential of $7.50 per barrel of oil for the first 6,000 barrels of oil purchased per day and differential of $5.50 per barrel for amounts in excess of 6,000 barrels per day, with such pricing effective on May 1, 2016. In 2016, Western entered into a pre-merger agreement with Tesoro Corporation. Upon closing of this agreement, we do not anticipate that our business relationship will be negatively impacted; however, we cannot provide assurance of such conclusion. If, for any reason, Western is unable to process our oil, there is alternative access to markets through rail and truck facilities or through the FERC-regulated Texas-New Mexico pipeline owned by Western. Furthermore, oil can be trucked to the refineries or oil pipelines in southern New Mexico, west Texas or Salt Lake City, Utah.

Resolute is party to a cooperative agreement with NNOGC related to the Aneth Field Properties (the "Cooperative Agreement"). Pursuant to the Cooperative Agreement, as modified on March 9, 2017, NNOGC holds an option to purchase an additional 10% of Resolute's interest in the Aneth Field Properties. The option is exercisable until July 2017 at the fair market value of such interest.

The following table presents, as of December 31, 2016, our estimate of the future capital expenditures, net to our interest, for purchases of CO_2 required to implement compression upgrades in the McElmo Creek Unit through 2036. The table also presents the estimated net PDNP reserves that we anticipate will be produced as a result of this project, as included in our December 31, 2016, 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)			

McElmo Creek Unit — C5 Upgrade and New Compressor (PDNP)	$7.6	2.3	$ 3.28	$ 15.1

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 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 project has been through early stages of engineering design and is currently on hold pending recovery of gas and NGL prices.

The saleable gas stream is currently transported to the San Juan Gas Plant in Fruitland, New Mexico. We are paid on a percent of proceeds basis that resulted in an average price of $1.31 per Mcf during 2016.

Divestiture of Wyoming Properties

In October 2015 we sold our Hilight Field interests in the Powder River Basin for approximately $55 million. The sale was consummated on October 6, 2015, with an effective date of July 1, 2015.

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, 2016, 2015 and 2014 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,		
	2016	2015	2014
Net proved developed reserves			
Oil (MBbl)	30,026	25,672	34,359
Gas (MMcf)	24,209	7,098	25,775
NGL (MBbl)	3,595	1,019	2,791
MBoe (1)	37,656	27,874	41,446
Net proved undeveloped reserves			
Oil (MBbl)	13,778	3,076	29,356
Gas (MMcf)	28,238	6,761	11,023
NGL (MBbl)	4,127	1,043	1,579
MBoe (1)	22,611	5,246	32,772
Total net proved reserves			
Oil (MBbl)	43,804	28,747	63,715
Gas (MMcf)	52,448	13,859	36,798
NGL (MBbl)	7,722	2,063	4,370
MBoe (1)	60,267	33,120	74,218
PV-10 ($ in millions) (2)(3)	344	199	973
Discounted future income taxes ($ in millions)	—	—	(140)
Standardized measure ($ in millions) (2)(4)	344	199	833

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, 2016, 2015 and 2014, were determined utilizing prices equal to the respective twelve-month unweighted arithmetic average using first day of the month prices, resulting in an average NYMEX WTI oil price of $42.75, $50.28 and $94.99 per Bbl for the Aneth Properties and Plains Marketing, L.P. posted WTI oil price of $39.25, $46.79 and $91.48 per Bbl for the Permian Properties, and an average Platts Gas Daily El Paso San Juan Basin spot gas price of $2.33, $2.46, and $4.31 per MMBtu for the Aneth Properties and Platts Gas Daily El Paso Permian Basin spot gas price of $2.31, $2.45, and $4.25 per MMBtu for the Permian Properties, respectively.
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 2016 estimates, are significantly lower than 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, among other factors, 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 13 — 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.

Our facility construction and well development activities began on CO_2 flood projects in Aneth Field in 2006, with CO_2 injection commencing in 2007 in Aneth Unit, and are ongoing although at reduced levels due to the current low commodity price environment. No CO_2 flood project proved undeveloped reserves were converted to proved developed in 2016.

Our operated drilling focus in 2016 was to preserve term leasehold acreage in the Permian Basin Properties primarily by targeting drilling on non-proved locations. During 2016, 22,491 gross MBoe of proved developed producing reserves were added to the proved reserves base through a successful blend of both operated and non-operated drilling of 15 gross non-proved locations in 2016 and late 2015, and through acquisition of additional ownership in those wells during 2016. No proved undeveloped reserves were converted into proved developed producing during 2016. An incremental 14 gross 2016 wells were drilled which, together with one later 2015 gross well, yielded total additions of 14,762 MBoe net of proved developed producing reserves and 17,957 MBoe net of proved undeveloped reserves through the addition of 20 gross immediate offset proved undeveloped Permian locations. These numbers include 907 MBoe of net proved producing reserves and 1,755 MBoe of net proved undeveloped reserves attributable to the acquisition of additional ownership in wells drilled, and existing leasehold, during 2016. These numbers also include 2016 production of 3,519 gross (2,214 net) MBoe.

Additionally, 4,486 MBoe of net proved developed non-producing and proved undeveloped reserves were added to Aneth Field in connection with newly identified compression and well deepening projects

With respect to the properties included in our prior year reserve reports, we incurred development costs of $31.1 million in 2016 as compared to $39.8 million in 2015. The year over year change in developmental costs is also reflective of our operated drilling focus in 2016 to preserve term leasehold acreage in the Permian Basin. With respect to the total proved value, 2 gross (1.7 net) 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 plans to drill two alternative non-proven locations that will convert the leasehold to held-by-production status prior to any lease expiration. Without consideration of continuous drilling operations and lease conversion activity, total proved reserves would be adversely affected by 2.2% on a volumetric basis and 0.4% on a value basis.

At December 31, 2016, no proved undeveloped reserves have remained, or are scheduled to remain, undeveloped beyond five years from its corresponding initial booking date.

8

Changes in Proved Reserves

Proved reserves reported by us at December 31, 2016, increased from those reported at December 31, 2015, as follows:

	Oil Equivalent (MBoe)
Proved reserves as of December 31, 2015	33,120
Production	(5,182)
Extensions, discoveries and other additions	34,543
Purchases of minerals in place	3,323
Sales of minerals in place	—
Revisions of previous estimates	(5,537)
Proved reserves as of December 31, 2016	60,267
Proved developed reserves:	
As of December 31, 2016	37,656
Proved undeveloped reserves:	
As of December 31, 2016	22,611

Extensions, discoveries and other additions to proved reserves were the result of drilling wells in the Permian Basin and new compression and well deepening projects in Aneth Field.

The Permian Basin 2016 drilling program resulted in total additions of 14,762 net MBoe of proved developed producing reserves, which included 13,855 net MBoe from the successful drilling of non-proved locations and 907 net MBoe from the acquisition of additional interests in these wells during 2016. These successful wells also created additional proved undeveloped offset locations of 17,957 net MBoe, which included 16,202 net MBoe related to the addition of the 20 immediate offset proved undeveloped Permian location and 1,755 net MBoe related to the acquisition of additional ownership in existing leases. No proved undeveloped locations were developed during 2016.

Additionally, 4,486 MBoe of net proved developed non-producing and proved undeveloped reserves were added to Aneth Field in connection with newly identified compression and well deepening projects.

In accordance with SEC requirements, the oil reserves at December 31, 2016 and 2015, utilized average NYMEX West Texas Intermediate oil prices of $42.75 and $50.28 per Bbl, respectively, for the Aneth Properties and average Plains Marketing, L.P. posted West Texas Intermediate oil prices of $39.25 and $46.79 per Bbl, respectively, for the Permian Basin Properties. For gas, the reserves at December 31, 2016 and 2015, utilized average Platts Gas Daily El Paso San Juan Basin spot gas price of $2.33, $2.46, and $4.31 per MMBtu for the Aneth Properties and Platts Gas Daily El Paso Permian Basin spot gas price of $2.31, $2.45, and $4.25 per MMBtu for the Permian Properties, respectively.

Revisions of previous estimates primarily relate to projects that had economically proved reserves at December 2015 average prices, but were not economically proved reserves at December 2016 average prices.

Controls Over Reserve Report Preparation, Technical Qualification and Methodologies Used

Reserve estimates as of December 31, 2016, were prepared by Resolute and audited by Netherland Sewell and Associates, Inc. (“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 White. Mr. White has more than 32 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 Utah, Wyoming, North Dakota and Washington state. 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 registered as a 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 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 Mr. David Miller. Mr. Miller has been practicing consulting petroleum engineering at NSAI since 1997. He is a Registered Professional Engineer in the States of Texas and Louisiana and has more than 35 years of practical experience in petroleum engineering, with more than nineteen 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's qualifications meet or exceed 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, 2016, 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 2016, 2015 and 2014.

	Year Ended December 31,		
	2016	2015	2014
Sales Data:			
Oil (MBbl)	3,821	3,271	3,488
Gas (MMcf)	4,811	5,194	5,023
NGL (MBbl)	559	400	320
Combined volumes (MBoe)	5,182	4,536	4,645
Daily combined volumes (Boe per day)	14,157	12,427	12,727
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$38.83	$42.16	$84.28
Gas ($/Mcf)	2.22	2.43	5.23
NGL ($/Bbl)	9.80	10.32	28.58
Average Production Costs ($/Boe):			
Lease operating expense	$12.29	$17.50	$24.26
Production and ad valorem taxes	3.14	4.41	8.01

In each of the years presented above, total estimated proved reserves attributed to our Delaware Basin Project area and Aneth Field exceeded fifteen percent of our total proved reserves expressed on an equivalent basis. Therefore, the tables below summarize our operating data for the Delaware Basin Project area and Aneth Field for 2016, 2015 and 2014.

Delaware Basin Project area:

	Year Ended December 31,		
	2016	2015	2014
Sales Data:			
Oil (MBbl)	1,489	393	209
Gas (MMcf)	3,989	1,579	615
NGL (MBbl)	549	224	90
Combined volumes (MBoe)	2,704	880	401
Daily combined volumes (Boe per day)	7,387	2,412	1,099
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$42.25	$43.50	$75.51
Gas ($/Mcf)	2.40	2.29	4.20
NGL ($/Bbl)	9.64	7.89	22.32
Average Production Costs ($/Boe):			
Lease operating expense	$4.62	$7.47	$14.63
Production and ad valorem taxes	2.14	2.67	3.92

Aneth Field:

	Year Ended December 31,		
	2016	2015	2014
Sales Data:			
Oil (MBbl)	2,132	2,172	2,249
Gas (MMcf)	739	717	276
NGL (MBbl)	—	—	—
Combined volumes (MBoe)	2,255	2,292	2,295
Daily combined volumes (Boe per day)	6,161	6,279	6,287
Average Realized Prices (excluding derivative settlements):			
Oil ($/Bbl)	$36.37	$40.81	$84.76
Gas ($/Mcf)	1.31	1.87	4.76
NGL ($/Bbl)	—	—	—
Average Production Costs ($/Boe):			
Lease operating expense	$20.24	$21.55	$27.08
Production and ad valorem taxes	4.31	5.98	11.04

11

Oil and Gas Wells

The following table sets forth information as of December 31, 2016, 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 326 gross (206 net) active water and CO_2 injection wells as of December 31, 2016.

	Productive Wells[1]	
	Gross	Net
Oil	466	319
Gas	1	—
Total	467	319

1) We operated 458 gross (318 net) productive wells at December 31, 2016.

Drilling Activity

The following table sets forth information with respect to exploration, development and extension wells we completed during 2016, 2015 and 2014. 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,		
	2016	2015	2014
Gross exploration wells:			
Productive [1]	—	—	1
Dry [2]	—	—	—
Total exploration wells	—	—	1
Gross development wells:			
Productive [1]	—	1	8
Dry [2]	—	—	—
Total development wells	—	1	8
Gross extension wells:			
Productive [1][3]	14	5	11
Dry [2]	—	—	—
Total extension wells	14	5	11
Total gross wells drilled	14	6	20

	Year Ended December 31,		
	2016	2015	2014

Net exploration wells:			
Productive [(1)]	—	—	—
Dry [(2)]	—	—	—
Total exploration wells	—	—	—
Net development wells:			
Productive [(1)]	—	1	4
Dry [(2)]	—	—	—
Total development wells	—	1	4
Net extension wells:			
Productive [(1)(3)]	12	2	6
Dry [(2)]	—	—	—
Total extension wells	12	2	6
Total net wells drilled	12	3	10

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 the 2015 count is 1 gross (0.1 net) productive extension well sold to Qstar, LLC effective March, 1, 2015, closed May 1, 2015.

Acreage

All of our leasehold acreage is categorized as developed or undeveloped. The following table sets forth information as of December 31, 2016, relating to our leasehold acreage.

	Developed Acreage (1)	
Area	Gross (2)	Net (3)
Aneth Field (UT)	43,218	27,157
Permian Basin (TX)	15,393	12,703
Permian Basin (NM)	3,920	3,582
Wyoming	1,357	1,357
North Dakota	516	99
Total	64,404	44,898

	Undeveloped Acreage (4)	
Area	Gross (2)	Net (3)
Aneth Field (UT)	1,173	1,173
Permian Basin (TX)	4,564	3,681
Wyoming	2,196	2,196
Total	7,933	7,050

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 4,400 net acres (which includes 2,700 net acres of developed and undeveloped Wyoming acreage), 1,000 net acres and 1,000 net acres of undeveloped acreage will revert or expire in 2017, 2018 and 2019, respectively, absent activity to develop such acreage.

Present Activities

As of December 31, 2016, we were in the process of drilling 1 gross (1.0 net) well and there was 1 gross (1.0 net) well 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.

13

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%, 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. This right of first negotiation has been waived with respect to any transaction consummated prior to December 31, 2017 involving the Aneth Field assets.

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 until July 2017 at the 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 extended the term of the agreement until March 31, 2015 and provided that the term would continue thereafter on a month-to-month basis until terminated by a party with ninety days prior notice. On December 8, 2015, the Company entered into a second amendment to the agreement which provided for a reduction of the differential to $7.50 per barrel of oil. On May 9, 2016, the Company entered into a third amendment to the agreement which provides that Resolute and NNOGC will receive a price equal to NYMEX oil price minus a differential of $7.50 per barrel of oil for the first 6,000 barrels of oil purchased per day and a differential of $5.50 for amounts in excess of 6,000 barrels per day, with such pricing effective on May 1, 2016. In 2016, Western entered into a pre-merger agreement with Tesoro Corporation. Upon closing of this agreement, we do not anticipate that our business relationship will be negatively impacted; however, we cannot provide assurance of such conclusion. If, for any reason, Western is unable to process our oil, there is alternative access to markets through rail and truck facilities or through the FERC-regulated Texas-New Mexico pipeline owned by Western. Furthermore, oil can be trucked to refineries or oil pipelines in southern New Mexico, west Texas or Salt Lake City, Utah.

Western refines our oil at their 25,000 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. From there, crude is transported through a Western pipeline that serves the refinery. Our and NNOGC’s oil has been jointly marketed to Western. The combined Resolute and NNOGC volumes were approximately 8,900 barrels of oil per day as of year-end. When combined with the royalty barrels owned by the

Navajo Nation, Aneth Field provides approximately 10,300 barrels per day to the Gallup refinery, more than 40% 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, west Texas, or Salt Lake City, Utah, where structural changes in the regional oil supply have created a long term premium market for oil sales to the refineries there and have positioned Salt Lake City as a potentially attractive alternative market for Aneth Field crude oil sales. 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 may 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, the most significant purchasers of which were Western Refining Southwest Inc, Plains Marketing LP, and Holly Frontier LLC for 2016.

Gas and NGL Sales

Our gas and NGL are sold to various midstream processing companies under long-term percent of proceeds contracts, including Castleton Commodities International, LLC in the Aneth Field, Energy Transfer Partners, L.P. in the Delaware Basin Project area, and West Texas Gas and DCP Midstream in the Northwest Shelf Project area.

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 an additional 6.5% interest through another acquisition and are responsible for that total of approximately 31.5% 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, 2016, 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 $25.8 million had already been incurred and paid for. These costs do not include any costs for clean-up or remediation of the subsurface, nor for minor additional demolition and removal activity associated with buried piping and concrete foundations. In February 2016 Chevron notified the working interest owners of its intent to renew certain rights-of-way with the Navajo Nation in anticipation of renewed clean-up activity at the site. Chevron has budgeted approximately $0.4 million for right-of-way renewal and site assessment studies associated with possible asbestos contamination of soil at the site. Resolute's share of this cost is approximately $0.1 million. 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 or whether the prior owner will be able to satisfy their indemnity obligations. 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. Additionally, we reviewed 98% of the title opinions and public records related to the proved reserves in Lea County, New Mexico.

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 seek to hire qualified employees and 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 they 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. Furthermore, regulatory and overall public scrutiny focused on the oil and gas industry is increasing significantly. 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 the Navajo Nation CERCLA. 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 solid and 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. 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, 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. Before commencing construction on a new or modified source of air emissions, these 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, ExxonMobil completed upgrades to the main flare in May 2006, and we have met all of the remaining material compliance measures of the consent decree. The EPA is processing the Title V application required by consent decree, and a final PSD permit was issued in the fourth quarter of 2016. 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 2017 by the EPA, although the EPA has given us no definite confirmation, and such termination may not be possible until a final Title V permit is 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 are minor sources even without emission controls did not need to obtain a permit prior to their construction for up to 48 months from the effective date of the rules, August 30, 2015 (although they needed to register with the EPA in most instances), while such sources that exceed major source thresholds without legally and practically enforceable emission control requirements in place 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. In June 2016 EPA published final amendments to the 2012 NSPS Subpart OOOO rules as well as new final rules focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. The new final rules in NSPS Subpart OOOOa impose requirements for leak detection and repair, control requirements at hydraulically fractured oil well completions, replacement of certain pneumatic pumps and controllers, and additional control requirements for gathering, boosting, and compressor stations, among other things. These final revised and new rules issued in 2013, 2014 and 2016 require modifications to our operations as promulgated, increasing our capital and operating costs without being offset by increased product capture. The revised and new final rules in NSPS Subparts OOOO and OOOOa are the subject of numerous court challenges currently pending in the federal Court of Appeals for the District of Columbia Circuit, although the rules remain effective and have not been stayed.

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 pending 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 September 2013, the EPA and U.S. Army Corps of Engineers released a Connectivity Report that determined that virtually all tributary streams, wetlands, open water in floodplains and riparian areas are connected. This report supported the final rule issued in June 2015 that clarifies the scope of the agencies' jurisdiction under section 404 of the CWA to regulate certain activities occurring in Waters of the United States. This rule, known as the Clean Water Rule, has been challenged by various parties in multiple federal courts, and as a result of this litigation is currently stayed and not yet effective.

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 $25,000 per year. Onsite activities were concluded and a transition to passive monitoring was implemented in 2014 with final closure anticipated in 2017.

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 drilling new 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 $0.1 million to over $0.3 million 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 such 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 such 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, with a subsequent emissions reduction commitment for the period from 2013 through 2020. Although a successor treaty to the Kyoto Protocol has not been developed to date, further GHG regulation may result from the December 2015 agreement reached at the United Nations climate change conference in Paris (the Paris Agreement). Pursuant to the Paris Agreement, the United States made an initial pledge to a 26-28% reduction in its GHG emission by 2025 against a 2005 baseline and committed to periodically update its pledge in five yearly intervals starting in 2020. In response to such studies and international action, the U.S. Congress has considered but not yet 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 GHG Tailoring Rule became effective for all new facilities that emit at least 100,000 tons of GHG per year, but the rule was challenged in federal court on various legal grounds. In June 2014, the United States Supreme Court’s holding in Utility Air Regulatory Group v. EPA upheld a portion of EPA’s GHG stationary source permitting program, but also invalidated a portion of it. Upon remand, the EPA is considering how to implement the Court’s decision. The Court’s holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels. 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 that the 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 final rule on October 22, 2015 that expanded the types of sources that are covered by the MRR. These sources 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.

In addition, President Obama released a Strategy to Reduce Methane Emissions in March 2014. Consistent with that strategy, the EPA issued a final rule in 2016 that set additional standards for methane and volatile organic compound emissions from oil and gas production sources, including hydraulically fractured oil wells and natural gas processing and transmission sources. As noted above, the new final rules in NSPS Subparts OOOOa are the subject of numerous court challenges currently pending in the federal Court of Appeals for the District of Columbia Circuit, although the rules remain effective and have not been stayed. In addition, the federal Bureau of Land Management (BLM) has proposed standards for reducing venting and flaring on public lands. The final rule was published in the Federal Register on November 18, 2016. The final rule is also the subject of pending litigation in the District of Wyoming federal court by industry members and certain states seeking to overturn the rule in part. Although the court denied a request for preliminary injunction to prevent the rule from taking effect on January 17, 2017, it has also set an expedited briefing schedule for hearing the plaintiffs' arguments on the merits for overturning parts of the BLM rule, and a decision is expected in the Spring/Summer of 2017. The EPA and BLM actions are part of a series of steps by the Obama Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels. In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

In November 2016, the EPA also issued a final Information Collection Request (ICR) to the oil and gas industry to support development of new regulations covering methane emissions at existing oil and gas sites. There will be both an "operator survey" and a "facility survey" response due in 2017, with greater detail required in the "facility survey". This process could result in additional regulations on existing oil and gas sites potentially leading to increased operating and compliance costs.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and could reduce demand for our products.

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 we have been successful thus far in obtaining 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. Although the five year period has passed since entering into this agreement, Navajo Nation has not taken any steps to enforce Navajo CERCLA. 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;
- the underground injection of salt water; 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 in the rock 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 released a final report on 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, in April 2015, the EPA proposed regulations under the Clean Water Act to impose pretreatment standards on wastewater discharges associated with hydraulic fracturing activities. In December 2016, the EPA released its final report on the potential impacts to drinking water resources from hydraulic fracturing, which concludes that hydraulic fracturing activities can impact drinking water resources under some circumstances. In addition, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices.

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. In October 2015, EPA also granted, in part, a petition filed by several national environmental advocacy groups to add the oil and gas extraction industry to the list of industries required to report releases of certain "toxic chemicals" in the environment under the Toxics Release Inventory ("TRI") program under of the Emergency Planning and Community Right-to-Know Act (EPCRA). That action resulted in EPA's publication in the Federal Register in January 2017, of proposed rules to achieve the inclusion of gas processing in EPCRA reporting requirements. Comments on the proposed rules are due in March 2017.

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, in December 2015 the U.S. Department of Labor and the U.S. Department of Justice released a Memorandum of Understanding ("MOU"), announcing an interagency effort to increase enforcement of worker endangerment violations under environmental statutes (such as the Clean Water Act, the Clean Air Act, and the Resource Conservation and Recovery Act) and Title 18 criminal statutes that carry harsher penalties that the Occupational Safety and Health Act of 1970. Consistent with this MOU, where appropriate, DOJ will seek felony charges (such as false statements, conspiracy, and obstruction of justice) when prosecuting worker endangerment violations. 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. As noted above, the EPA finalized a wide-ranging study on the effects of hydraulic fracturing on drinking water resources in 2016. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing. For example, a federal BLM rulemaking for hydraulic fracturing practices on federal and Indian lands resulted in a 2015 final rule that requires public disclosure of chemicals used in hydraulic fracturing, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing related flowback water. 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. 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, 2016, we had 206 full-time employees, of which 39 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. 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 22,000 square feet of office space in Midland, Texas. Our principal office is located at 1700 Lincoln, Suite 2800, Denver, CO 80203. In addition, we own and maintain field offices in Utah 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, CO 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.

27

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. Sustained periods of low prices or 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 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. Oil and gas prices have declined substantially since mid 2014 and continued to decline into early 2016. For example, during the twelve months ended December 31, 2016, the NYMEX price for light sweet crude oil ranged from a high of $54.06 per Bbl to a low of $26.21 per Bbl. For calendar year 2015, the range was from a high of $61.43 per Bbl to a low of $34.73 per Bbl, and for the five years ended December 31, 2016, the price ranged from a high of $110.53 per Bbl to a low of $26.21 per Bbl.

A prolonged period of low oil and gas prices or a decline in oil and gas prices will significantly affect many aspects of our business, including financial condition, revenue, results of operations, liquidity, cash flow, rate of growth, reserves, the carrying value of our oil and gas properties, and the borrowing base under our revolving credit facility with a syndicate of lenders (the “Revolving Credit Facility”), 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.

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, 8.5% senior notes due 2020 (the "Senior Notes") or future debt agreements;
- the effectiveness of our commodity price hedging strategy;
- the development of proved undeveloped and other prospective 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 and prospective properties;
- 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, 2016, was based on a pricing methodology required by SEC rules. 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.

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, including in the event of acquisitions or dispositions of properties.

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 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 fund our operations, exploration and development efforts, acquisitions, working capital, capital expenditures and other general corporate purposes;
- 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;
- may prevent counterparties (including lenders) from entering into derivative transactions with us;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage relative to our competitors that have less debt outstanding.

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

Our Revolving Credit Facility and the indenture governing our 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.

As amended in February 2017, our Revolving Credit Facility will mature in 2021, unless extended, and is secured by substantially all of our oil and gas properties as well as a pledge of all ownership interests in our operating subsidiaries. The Revolving Credit Facility contains various affirmative and negative covenants, measured on a quarterly basis, including but not limited to financial covenants that (i) require us to maintain a ratio of current assets to current liabilities of no less than 1.0 to 1.0 and (ii) do not permit our maximum leverage ratio (total debt to consolidated Adjusted EBITDA as defined in the Revolving Credit Facility) to exceed 4.0 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, 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 affect 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 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 to avoid being in default. If we breach our covenants under our Revolving Credit 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 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 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.

The marketability of our production is dependent upon transportation and processing facilities the capacity and operation of which we do not control. In particular, 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, gas processing facilities, water sourcing, gathering and disposal systems and oil gathering systems 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 8, 2015, 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 $7.50 per barrel of oil. On May 9, 2016, the Company entered into another amendment to the agreement which provides that Resolute and NNOGC will receive a price equal to NYMEX oil price minus a differential of $7.50 per barrel of oil for the first 6,000 barrels of oil purchased per day and a differential of $5.50 for amounts in excess of 6,000 barrels per day, with such pricing effective on May 1, 2016. The term of the purchase agreement is on a month-to-month basis until terminated by either party with ninety days prior notice. In

2016, Western entered into a pre-merger agreement with Tesoro Corporation. Upon closing of this agreement, we do not anticipate that our business relationship will be negatively impacted; however, we cannot provide assurance of such conclusion. If, for any reason, Western is unable to process our oil, there is alternative access to markets through rail and truck facilities or through the FERC-regulated Texas-New Mexico pipeline owned by Western. Furthermore, oil can be trucked to refineries or oil pipelines in southern New Mexico, west Texas or Salt Lake City, Utah.

Western refines our oil at their 25,000 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 twenty miles south of Farmington, New Mexico. From there, crude is transported through a Western pipeline that serves the refinery. We and NNOGC jointly market our oil to Western. The combined volumes were approximately 8,900 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 twenty and 50 days of production revenue. Based upon average production from Aneth Field during the quarter ended December 31, 2016, and a NYMEX oil price of $52.17 per Bbl, Western could owe us between $5.4 million and $13.6 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 or other 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 regulations and 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;
- midstream constraints or downtime;
- 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.

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.

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.

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 Revolving Credit Facility or the Senior Notes, or to fund other liquidity needs. As of December 31, 2016, we had $538.3 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 Revolving Credit Facility or the Senior Notes.

Declines in product prices decrease our operating cash flow. 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 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. Estimates of resource potential are also based on many assumptions and may turn out to be inaccurate.

Our estimate of proved reserves at December 31, 2016, 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, on a well-by-well basis, the reserve and economic evaluations of all properties that were prepared by us. 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 necessarily subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities of oil and gas that are ultimately recovered;
- the timing of the recovery of oil and gas reserves;
- the production and operating costs incurred; and
- the amount and timing of future development expenditures.

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

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly.

In addition, the present value of the estimated future net cash flows from our proved reserves is not necessarily the same as the current market value of those reserves. Pursuant to SEC rules, the estimated future net cash flows from our proved reserves, and the estimated quantity of those reserves, were based on the arithmetic average of the prior year's first day of the month crude oil and index prices. Because market prices for crude oil at the end of 2016 were significantly higher than the average price for the year determined under SEC rules, the estimated quantity and present values of our reserves presented in this report using SEC pricing are lower than they would be if we had used year-end commodity prices instead.

In our press releases and investor presentations, 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, "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.

Sustained low commodity prices could result in additional impairments charges and 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. 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.

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 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 $287.9 million of capital expenditures (including CO_2 purchases) over the next nineteen years to maintain our proved developed producing, and to implement and complete our PDNP and PUD projects. We expect to incur approximately $227.9 million of these future capital expenditures during 2017 through 2020 based on the capital plan contemplated by our year-end 2016 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 or the Senior Notes, 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.

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

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

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

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 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 Revolving Credit Facility. 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 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. In addition, under the indenture, we will be able to make restricted payments in certain circumstances. We may also be able to obtain waivers from the lenders under our Revolving Credit Facility and the holders of our Senior Notes that would permit us to increase the amount of indebtedness we are permitted to incur. 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 are effectively subordinated to the rights of our and our restricted subsidiaries’ existing and future secured creditors.

The lenders under our Revolving Credit 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. The Revolving Credit Facility is 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 and any future secured facilities of the Company. 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 are 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.

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. A "change of control" under the indenture governing our Senior Notes includes the acquisition by a third party of more than 50% of our outstanding common stock, which is a transaction that may occur without the approval of the Company's Board of Directors.

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 restricts, 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 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 debt agreement) in itself would constitute an event of default under our Revolving Credit Facility.

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 has occurred.

The definition of change of control in the Revolving Credit Facility and the Senior Notes 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, 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.

Provisions in the indenture governing our Senior Notes and in our Revolving Credit Facility may discourage third parties from seeking to consummate a change of control transaction that could otherwise be beneficial for our stockholders.

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. 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, which would cause amounts outstanding under the Revolving Credit Facility to become immediately due and payable. The potential trigger of an event of default under the Revolving Credit Facility, as well as the potential repurchase obligation under the Senior Notes, may discourage potential third parties from entering into a change of control transaction with us that may otherwise be beneficial for our stockholders.

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, 2016, we had approximately 3,700 net acres in the Permian Basin that are not currently held by production. Unless production in paying quantities is established on units containing these leases during their primary term, their continuous drilling term 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.

Currently, a significant portion 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 48% of our 2016 oil and gas revenues and 41% of our net proved reserves at December 31, 2016, 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, 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 option 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 interests acquired from Denbury and other minority interests). This option is exercisable for cash until July 2017 at the fair market value of the interests. If NNOGC exercises its purchase option in full, it could acquire from us undivided working interests representing a 6.1% 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 although in connection with the amendment to the Cooperative Agreement executed on March 9, 2017, NNOGC waived its right of first negotiation for any transaction involving Aneth Field during 2017. 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."

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

Any or all of the following may occur if domestic and global 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 bears a floating interest rate 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 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.

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, distribution and disposal systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know with certainty 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 PUD reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUD reserves may not be ultimately developed or produced.

As of December 31, 2016, 38% 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 PUD reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. If we choose not to develop our PUD reserves or suffer delays in their development as a result of such factors we could have to reclassify our PUD reserves as unproved reserves. Under the SEC's reserve reporting rules, we may be required to write down our PUD reserves if we do not drill those wells within five years after their respective dates of initial booking. The current commodity price environment has resulted in a significant reduction in our PUD reserves and heightens the risk that existing and future PUD reserves may not be economic.

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 stabilized, substantially eliminating such shortages at the present time, we could experience such difficulties in the future. In that event, our 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. The expansion of GHG mandatory reporting rules (MRR) affecting onshore oil and natural gas activities and proposed GHG cap-and-trade legislation are two examples of recent and of proposed changes in the regulatory climate that do and would affect us. Also, the EPA has announced a comprehensive strategy for further reducing methane emissions from oil and gas operations and issued a final rule in June 2016 (Clean Air

Act NSPS Subpart OOOOa). 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.

Certain federal income tax deductions and credits currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

In addition, certain 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, including all of our wells in the Permian Basin. 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 EPA is conducting a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2015, the EPA issued a draft final report for public comment and peer review. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing. For example, a federal BLM rulemaking for hydraulic fracturing practices on federal and Indian lands resulted in a 2015 final rule that requires public disclosure of chemicals used in hydraulic fracturing, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing related flowback water. Several states filed suit against the Department of Interior over the final BLM hydraulic fracturing regulations, and as a result, in June 2016, the United States District Court for the District of Wyoming held that the new regulations were invalid. The case is now on appeal to the United States Court of Appeals for the Tenth Circuit, which lifted a stay of the rules imposed by the federal district court, pending final disposition on the merits. Oral argument was heard by the Tenth Circuit in January 2017. A ruling on the BLM’s appeal of the district court’s decision invalidating these regulations is expected in the second calendar quarter of 2017 or later.These activities could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. The U.S. Congress has considered legislation, and in the future may consider additional 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 amendments to the SDWA or these federal agencies’ possible expansion of their existing 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. We cannot assure you that any such outcome would not be material, and any such outcome could have a material and adverse impact on our cash flows and results of operations. Please read “Business and Properties —Other Regulation of the Oil and Gas Industry—Hydraulic Fracturing Disclosure and Possible Regulation or Prohibition” for a description of the potential further laws and regulations that may affect us.

Legislation or regulatory initiatives intended to address seismic activity could restrict our ability to dispose of saltwater produced in connection with our oil and gas production, which could limit our ability to produce oil and gas economically and have a material adverse effect on our business.

We dispose of large volumes of saltwater produced in connection with our drilling and production operations, pursuant to permits issued to us or third party operators of disposal wells by governmental authorities overseeing produced water disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such disposal activities.

There exists a growing concern that the injection of produced water into deep belowground disposal wells may trigger seismic activity in certain areas, including Texas, where we operate. In response to these concerns, regulators in some states are pursuing initiatives designed to impose additional requirements in the permitting of saltwater disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismic activity that may be attributable to fluid injection or oil and natural gas extraction activities. In addition, a number of lawsuits have been filed in other states, including recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in October 2014, the Texas Railroad Commission, or TRC, published a new rule governing permitting or re-permitting of disposal wells in Texas that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If a permittee or a prospective permittee fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

The adoption and implementation of any new laws, regulations, or directives that restrict our ability to dispose of produced water, by changing the depths of disposal wells, reducing the volumes, injection pressures or rates of oil and gas wastewater disposal in such wells, restricting disposal well locations, or by requiring us or third parties who dispose of our saltwater to shut down disposal wells, could increase disposal costs or require us to shut in a substantial number of our oil and gas wells or otherwise have a material adverse effect on our ability to produce oil and gas economically and, accordingly, could materially and adversely affect our business, financial condition and results of operations.

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.

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 52% of our 2016 oil and gas revenues and 59% of our total proved reserves at December 31, 2016, are located in our Permian Basin Properties in west Texas and southeast New Mexico. Essentially all of the remainder of our sales of oil and gas and total proved reserves are attributable to our Aneth Field 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.

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 ownership interest could be diluted or forfeited.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties own the remaining portion of the working interest. We could be responsible for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in commodity prices may increase the likelihood that some of these working interest owners will not be able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

The inability of one or more of our customers or other counterparties to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from our crude oil, gas and NGL sales or joint interest billings to a small number of third parties in the energy industry. This concentration of customers and joint interest owners may affect our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our derivatives expose us to credit risk in the event of nonperformance by counterparties. Nonperformance by our customers or derivative counterparties may adversely affect our financial condition. We face similar risks with respect to our other counterparties, including the lenders under our Revolving Credit Facility and the providers of our surety bonds and insurance coverage.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies we currently use or implement in the future may become obsolete. We cannot be certain we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Our derivative activities could result in financial losses or reduced income from failure to pay by our counterparties, could reduce our net income, and could result in volatility in 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. 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."

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.

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.

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.

Our Revolving Credit Facility as amended and restated on February 17, 2017, prohibits us from entering into derivative arrangements for more than (i) 85% of our anticipated production from proved properties in the next two years and (ii) the greater of 75% of our anticipated production from proved properties or 85% of our production from projected proved developed producing properties after such two year period, 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. 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, former 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, and could have a number of effects on us, including 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 or at all.

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 and Denbury, which is 31% 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. $25.8 million has already been incurred and paid for as of December 31, 2016. 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. In February 2016 Chevron notified the working interest owners of its intent to renew certain rights-of-way with the Navajo Nation in anticipation of renewed clean-up activity at the site. Chevron has budgeted approximately $0.4 million for right-of-way renewal and site assessment studies associated with possible asbestos contamination of soil at the site. Resolute's share of this cost is approximately $0.1 million.

The Aneth Gas Processing Plant site was previously evaluated by the 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 31.5% 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.

A significant part of our Aneth Field 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. 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 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.

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 the warming of the Earth's atmosphere and significant physical effects, such as increased frequency and severity of storms, floods and other climatic events, any of which could have an adverse effect in our operations. 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, federal and state courts and administrative agencies are considering the scope and scale of climate change regulation under various laws pertaining to the environment, energy use and development, and several states have already taken legal measures to reduce emissions of GHG. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for oil and gas. As a result of the U.S. Supreme Court's decision in April 2007, in Massachusetts v. EPA and subsequent decisions, the EPA also may regulate GHG emissions from mobile and stationary sources under the Clean air Act even if Congress does not adopt new legislation specifically authorizing such regulation. 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 to curb their GHG emissions.

In June 2016, the EPA finalized new regulations that set methane emission standards for new and modified oil and gas production and gas processing and transmission facilities. These rules are currently effective pending legal challenge in the United States Court of Appeals for the District of Columbia Circuit. In addition, the federal Bureau of Land Management (BLM) has published final standards for reducing venting and flaring of natural gas on public lands in November 2016. That final BLM rule is also the subject of pending litigation, in the District of Wyoming federal court, by industry members and certain states seeking to overturn the rule in part. The EPA and BLM actions are part of a series of steps by the Obama Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and gas industry as compared to 2012 levels.

In January 2015, former President Obama announced a comprehensive strategy to further reduce methane emissions from the oil and gas sector. As part of this strategy, in September 2015 the EPA published proposed amendments to the 2012 New Source Performance Standards (“NSPS”) Subpart OOOO rules focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. In June 2016 EPA published final amendments to the 2012 NSPS Subpart OOOO rules, as well as new final rules focused on achieving additional methane and volatile organic compound reductions from the oil and natural gas industry. The new final rules in NSPS Subpart OOOOa impose requirements for leak detection and repair, control requirements at hydraulically fractured oil well completions, replacement of certain pneumatic pumps and controllers, and additional control requirements for gathering, boosting, and compressor stations, among other things. These final revised and new rules issued in 2013, 2014 and 2016 require modifications to our operations as promulgated, increasing our capital and operating costs. The revised and new final rules in NSPS Subparts OOOO and OOOOa are the subject of numerous court challenges currently pending in the federal Court of Appeals for the District of Columbia Circuit, although the rules remain effective and have not been stayed.

In November 2016, the EPA also issued a final Information Collection Request (ICR) to operators in the oil and gas industry to support development of new regulations covering methane emissions at existing oil and gas sites. There will be both an "operator survey" and a "facility survey" response due in 2017, with greater detail required in the "facility survey." This process could result in additional regulations on existing oil and gas sites potentially leading to increased operating and compliance costs.

In addition, substantial limitations on GHG emissions in other sectors, such as the power sector under the EPA’s August 2015 Clean Power Plan, the implementation of which was stayed indefinitely by the U.S. Supreme Court in February 2016, could adversely affect demand for the oil and gas we produce. Further GHG regulation may result from the December 2015 agreement reached at the United Nations climate change conference in Paris. The United States was actively involved in the international negotiations in Paris. Pursuant to the Paris Agreement, the United States made an initial pledge to a 26-28% reduction in its GHG emission by 2025 against a 2005 baseline and committed to periodically update its pledge in five yearly intervals starting in 2020. The Paris Agreement sets a goal of keeping global warming well below two degrees Celsius and sets a target limit of 1.5 degrees. The Paris Agreement was signed by the United States in April 2016. 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.

It is uncertain whether our operations and properties, located in the southern region of the United States, are exposed to possible physical risks, such as severe weather patterns due to climate change, whether or not climate change is being caused or contributed to by anthropogenic emissions of GHG.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant GHG emissions. Such cases may seek to challenge air emissions permits that GHG emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property. Any laws or regulations that may be adopted to restrict or reduce emissions of GHG could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and could reduce demand for our products.

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.

In April 2012, the EPA issued final rules that established additional NSPS emission controls for oil and gas production and gas processing operations, the NSPS Subpart OOOO rules. After several parties challenged these regulations in court, the EPA administratively reconsidered certain of the rules' requirements. As a result of such administrative reconsideration, the EPA issued final amendments to the NSPS subpart OOOO regulations in September 2013 and December 2014. Specifically, the EPA's revised rules package included provisions 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 Subpart OOOO rules include a 95% reduction in volatile organic compound ("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. In June 2016, EPA published additional final amendments to the 2012 NSPS Subpart OOOO rules, as well as new final rules focused on achieving additional methane and VOC reductions from the oil and natural gas industry. The new final rules in NSPS Subpart OOOOa impose requirements for leak detection and repair, control requirements at hydraulically fractured oil well completions, replacement of certain pneumatic pumps and controllers, and additional control requirements for gathering, boosting, and compressor stations, among other things. The revised and new final rules in NSPS Subparts OOOO and OOOOa are the subject of numerous court challenges currently pending in the U.S. Court of Appeals for the District of Columbia Circuit, although the rules remain effective and have not been stayed.

In December 2014, the EPA proposed to revise and lower the existing 75 ppb National Ambient Air Quality Standards ("NAAQS") for ozone under the federal Clean Air Act to a range within 65-70 ppb. On October 1, 2015, EPA finalized a rule lowering the standard to 70 ppb. In November 2016, EPA proposed a rule for implementing the new NAAQS, classifying nonattainment areas, and related State Implementation Plan requirements. The lowered ozone NAAQS could result in an expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and 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 air quality 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, 2016, 39 of our field level employees were represented by the USW, and covered by a collective bargaining agreement. Although we believe that our relations with our employees are generally satisfactory, if we are unable to reach agreement with any of our unionized work groups on future negotiations regarding the terms of their collective bargaining agreements, or if additional segments of our workforce become unionized, we may be subject to work interruptions or stoppages. In addition, work stoppages have occurred in the past as a result of protests by local tribal members. Work stoppages at the facilities of our customers or suppliers may also negatively affect our business. If any of our customers experience a material work stoppage, the customer may halt or limit the purchase of our products. Moreover, if any of our suppliers experience a work stoppage, our operations could be adversely affected if an alternative source of supply is not readily available. Any of these events could be disruptive to our operations and could adversely affect our business, financial position, results of operations, or cash flows.

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. We recently became victims of a “spear phishing” attack on one of our employees in which sensitive employee information was stolen. We immediately took all necessary and appropriate steps to mitigate losses for the Company and the individuals whose information was compromised. Although to date we have not experienced any material financial 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 and other operating 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 uncertain 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.

Our plans for future strategic acquisitions may require substantial capital, which we may be unable to obtain on favorable terms or at all 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 oil and gas producing and undeveloped properties. We actively evaluate the acquisition of properties that are prospective for production of oil, gas and NGL, particularly in the Permian Basin. 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 equity issuances, 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.

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. 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.

Delaware law and our amended and restated certificate of incorporation and bylaws could impede or discourage a takeover that our stockholders may consider favorable.

Our amended and restated certificate of incorporation 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;
- advance notice procedures with respect to stockholder proposals and the nomination of candidates for election as directors; and
- a stockholder rights plan that allows any common stockholder to purchase Series A Junior Participating Preferred Stock for a specified amount 10 days after the public announcement that a person or a group has become an "Acquiring Person."

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 2016, trading between $2.25 and $42.34 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.

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. 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.

If we were to experience an "ownership change," we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income.

If we were to experience an "ownership change," as determined under section 382 of the Internal Revenue Code, our ability to offset taxable income arising after the ownership change with net operating losses (NOLs) arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate.

Risks Related to the Delaware Basin acquisitions

The Delaware Basin acquisitions may not achieve their intended results.

We consummated the Delaware Basin Firewheel Acquisition and entered into a Purchase and Sale Agreement relating to the Delaware Basin Orla Acquisition with the expectation that these acquisitions would result in various benefits, growth opportunities and synergies. Achieving the anticipated benefits of any transaction is subject to a number of risks and uncertainties. Title and other problems could reduce the value of the properties to us, and, depending on the circumstances, we could have limited or no recourse to Firewheel with respect to those problems. We assumed substantially all of the liabilities associated with the acquired properties and will be entitled to indemnification in connection with those liabilities in only limited circumstances and limited amounts. We cannot assure you that such potential remedies will be adequate for any liabilities we incur, and such liabilities could be significant.

The success of these acquisitions depends on, among other things, the accuracy of our assessment of the reserves associated with the acquired properties, future oil, NGL and gas prices and operating costs and various other factors. These assessments are necessarily inexact. As a result, we may not recover the purchase price for an acquisition from the sale of production from the property or recognize an acceptable return from such sales. Although the properties acquired are subject to many of the risks and uncertainties to which our business and operations are subject, risks associated with these acquisitions include those associated with the significant size of the transaction relative to our existing operations.

The reserves and production estimates with respect to the properties acquired in the Delaware Basin Firewheel Acquisition may differ materially from the actual amounts.

The reserves and production estimates with respect to the properties acquired in the Delaware Basin Firewheel Acquisition are based on our analysis of historical production data, assumptions regarding capital expenditures and anticipated production declines. We cannot assure you that these estimates are accurate.

Risks Related to our Convertible Preferred Stock

We are not obligated to pay dividends on the convertible preferred stock and no payment or adjustment will be made upon conversion for any undeclared or, subject to limited exceptions, unpaid dividends.

Quarterly dividends on the convertible preferred stock are only payable when, as and if declared by our Board or an authorized committee thereof. Our Board is not legally obligated to declare dividends, even if we have funds available for such purposes. Under Delaware law, dividends on capital stock may only be paid from “surplus” or, if there is no “surplus,” from the corporation’s net profits for the then-current or the preceding fiscal year. Further, even if adequate surplus is available to pay dividends on the convertible preferred stock, we may not have sufficient cash to pay dividends on the convertible preferred stock.

No allowance or adjustment will be made upon conversion for any undeclared or, subject to limited exceptions, unpaid dividends.

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, 2016 and 2015. The closing price of the common stock on February 28, 2017, was $46.55.

	2016		2015	
Period	High	Low	High	Low
1st Quarter	$4.40	$2.25	$7.10	$2.75
2nd Quarter	$3.85	$2.35	$9.00	$2.76
3rd Quarter	$26.50	$2.76	$4.85	$1.24
4th Quarter	$42.34	$22.27	$4.90	$1.96

As of February 28, 2017, there were approximately 202 record holders of our common stock.

In June 2016 Resolute filed a certificate of amendment to its certificate of incorporation to effect the previously-announced reverse stock split of the Company's common stock, par value $0.0001 per share, at a ratio of 1-for-5 (the "Reverse Stock Split"). The certificate of amendment also reduced the number of authorized shares of common stock from 225,000,000 to 45,000,000. The Reverse Stock Split, including the certificate of amendment, was approved by stockholders at the Company's 2016 annual meeting of stockholders and by the Company's Board of Directors. As a result, the Company is now in compliance with the $1.00 per share minimum price requirement of the NYSE. All historical share amounts disclosed have been retroactively adjusted to reflect the Reverse Stock Split.

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.

2016	Total Number of Shares Purchased (1)(2)	Average Price Paid Per Share
March 1 – 31	19,525	$ 3.05

April 1 – 30	1,377	$ 2.41
May 1 – 31	58	$ 3.28
June 1 – 30	221	$ 2.95
August 1 – 30	158	$ 6.16
September 1 – 30	470	$ 17.70
October 1 – 31	985	$ 29.68
November 1 – 30	70	$ 23.88
December 1 – 31	441	$ 41.01

1) All shares purchased in 2016 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, 2016, the maximum number of shares that may yet be purchased would not exceed the employees' portion of taxes withheld on unvested shares (249,342 common shares), outstanding stock options (1,052,513 options), shares yet to be granted under the Incentive Plan (1,056,430 shares) and potential Outperformance Shares (97,561 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. We pay quarterly dividends on the convertible preferred stock, although we are not legally required to declare or pay such dividends. 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, Senior Notes, financial condition, results of operations, working capital requirements, future prospects and other factors it considers relevant.

Stockholders Rights Plan

In May 2016 Resolute declared a dividend of one preferred share purchase right (a “Right”) for each outstanding share of common stock, par value $0.0001 per share. The Rights trade with, and are inseparable from, the common stock until such time as they become exercisable on the Distribution Date (described below). The Rights are evidenced only by certificates that represent shares of common stock and not by separate certificates. New Rights will accompany any new shares of common stock we issue after May 27, 2016, until the earlier of the Distribution Date described below and the redemption or expiration of the rights.

Each Right allows its holder to purchase from the Company one one-thousandth of a share of Series A Junior Participating Preferred Stock (a “Preferred Share”) for $4.50, once the Rights become exercisable. Prior to exercise, the Right does not give its holder any dividend, voting or liquidation rights. The Rights will not be exercisable until 10 days after the public announcement that a person or group has become an “Acquiring Person” by obtaining beneficial ownership of 20% or more of our outstanding common stock, or, if earlier, 10 business days (or a later date determined by the Board before any person or group becomes an Acquiring Person) after a person or group begins a tender or exchange offer which, if completed, would result in that person or group becoming an Acquiring Person.

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, 2016, 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, 2016. 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,				
	2016	2015	2014	2013	2012
	(in thousands, except per share data)				
Statement of Operation Data:					
Revenue	$164,478	$154,644	$329,371	$349,779	$258,268
Operating expenses	255,984	931,348	442,045	483,647	218,084
Income (loss) from operations	(91,506)	(776,704)	(112,674)	(133,868)	40,184
Other income (expense)	(70,125)	12,071	86,684	(44,617)	(10,327)
Income (loss) before income taxes	(161,631)	(764,633)	(25,990)	(178,485)	29,857
Income tax benefit (expense)	(91)	22,354	4,140	64,679	(11,881)
Net income (loss)	(161,722)	(742,279)	(21,850)	(113,806)	17,976
Earnings (loss) per share:					
Common stock, basic	$(10.33)	$(49.55)	$(1.50)	$(8.35)	$1.50
Common stock, diluted	$(10.33)	$(49.55)	$(1.50)	$(8.35)	$1.50
Weighted average shares outstanding:					
Common stock, basic	15,767	14,986	14,760	13,652	11,885
Common stock, diluted	15,767	14,986	14,760	13,652	11,890
Selected Cash Flow Data:					
Net cash provided by operating activities	$83,719	$69,479	$143,468	$133,328	$76,771
Net cash provided by (used in) investing activities	(190,467)	199,583	(175,893)	(405,518)	(447,447)
Net cash provided by (used in) financing activities	230,540	(264,117)	36,758	271,275	370,475

	As of December 31,				
	2016	2015	2014	2013	2012
	(in thousands)				
Balance Sheet Data:					
Total assets	$588,373	$390,983	$1,439,707	$1,468,809	$1,364,130
Long term debt	405,975	514,995	759,942	736,671	563,865
Total liabilities	664,120	594,264	913,089	935,257	831,946
Stockholders' equity (deficit)	(75,747)	(203,281)	526,618	533,552	532,184

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.

Resolute Energy Corporation, a Delaware corporation incorporated on July 28, 2009, is a publicly traded, independent oil and gas company with assets located primarily in the Delaware Basin in west Texas (the "Permian Properties" or "Permian Basin Properties") and Aneth Field located in the Paradox Basin in southeast Utah (the "Aneth Field Properties" or "Aneth Field"). Our development activity is focused on our 20,000 gross (16,400 net) operated acreage position in what we believe to be the core of the Wolfcamp horizontal play in northern Reeves County, Texas. Our corporate strategy is to drive organic growth in reserves, production and cash flow through development of our Reeves County acreage and opportunistic bolt-on acquisitions in the Delaware Basin while continuing to focus on improving margins in our Aneth Field Properties while de-risking certain future growth projects through selectively targeted capital investment.

As of December 31, 2016, we estimated net proved reserves were approximately 60.3 MMBoe, of which approximately 59% were proved developed producing reserves and approximately 73% were oil. The standardized measure of our estimated net proved reserves as of December 31, 2016, was $344 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.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. We recorded non-cash impairments of the carrying value of our proved oil and gas properties of $120 million, $705 million, and $58 million during 2014, 2015 and 2016, respectively, as a result of the ceiling test limitation. If in future periods a negative impact continues on one or more of the components of the calculation, including market prices of oil and gas (based on a trailing twelve-month unweighted average of the oil and gas prices in effect on the first day of each month), differentials from posted prices, future drilling and capital plans, operating costs or expected production, the Company may incur further full cost ceiling impairment related to its oil and gas properties in such periods.

In 2016, our Board of Directors approved a capital budget of between $115 million and $135 million, primarily focused on continuing horizontal development of our Delaware Basin Wolfcamp resource base in Reeves County, Texas, (our "Reeves County Assets") where we planned to drill and complete a total of nine wells (inclusive of the four wells above). Capital spending in Aneth Field has been limited to acquisition of CO_2, upgrades in electrical infrastructure and basic field maintenance. The drilling success achieved in our Reeves County Assets during the first half of 2016 led us to expand our 2016 drilling program by adding five additional wells (for a total of fourteen wells during 2016). Because these additional wells were drilled in the third and fourth quarters, they did not materially contribute to aggregate 2016 production. However, these wells added to our 2016 exit production rate and will provide momentum to our 2017 production volumes. Our 2016 capital plan reflected our intention to make investments in assets that are accretive to net asset value at current prices and to grow proved reserves and production that will benefit the Company as we move through 2017.

For 2017, we expect to incur capital expenditures of $210 to $240 million, primarily focused on following our successful 2016 performance in the Delaware Basin with a two rig drilling program spudding 22 gross wells. We expect the 2017 program to accomplish a number of important initiatives for the Company. We will further delineate our development inventory as we drill wells across our acreage block, conduct multiple spacing tests and complete wells in multiple landing zones in the Wolfcamp A as well as in the Wolfcamp B. The success of this program will help confirm the more than 370 Wolfcamp A and B development locations we believe exist in our Mustang and

Appaloosa project areas. We also expect that substantially all of our acreage will be held by production by the end of 2017.

We expect to outspend our cash flows from operations during 2017. A deterioration of commodity prices from current levels could negatively affect our results of operations, financial condition and future development plans. We may decrease our 2017 capital investment forecast during the year as a result of, among other things, a decline in commodity prices, drilling results, cost increases, or unfavorable changes in our borrowing capacity. We may also change our capital expenditure plan depending upon our ability to consummate the Delaware Basin Orla Acquistion and/or the potential divestiture of our Aneth Field assets.

On August 1, 2016, we closed the sale of our Reeves County gas gathering and produced water handling and disposal assets. This transaction provided approximately $36 million of net proceeds to Resolute, with $2 million held in escrow and the remaining proceeds used principally to repay all then outstanding Revolving Credit Facility debt. In connection with such sale, we also entered into long-term gas gathering and processing and water gathering and disposal agreements with the purchaser of such assets. On October 7, 2016, we closed the acquisition of certain Reeves County interests in the Delaware Basin for consideration consisting of $90 million in cash and 2,114,523 shares of our common stock. The cash paid for this acquisition was funded in part by net proceeds from the sale of preferred stock and borrowings on our Revolving Credit Facility of approximately $30 million. On December 23, 2016, we closed our public stock offering of 4,370,000 shares of common stock. The net proceeds from the offering, after deducting fees and estimated expenses, were approximately $160.9 million. With a portion of these proceeds, on January 3, 2017, we repaid approximately $132 million constituting all amounts due under the term loan facility (including prepayment fees). The second lien secured term loan facility (the “Secured Term Loan Facility”) was terminated in connection with the repayment. We will also continue to explore other ways to enhance our liquidity, de-lever our balance sheet and increase drilling activity, including potential asset sales and potential joint ventures. Such strategic initiatives are considered on an ongoing basis and decisions related thereto will be made if the terms are determined to be advantageous to us.

On February 22, 2017, we closed on the sale of our Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million, subject to customary purchase price adjustments. The effective date of this sale is October 1, 2016. The proceeds of the sale will be used for general corporate purposes.

On March 3, 2017, Resolute Natural Resources Southwest, LLC, a wholly-owned subsidiary of the Company, entered into a Purchase and Sale Agreement with undisclosed private sellers pursuant to which Buyer agreed to acquire certain producing and undeveloped oil and gas properties in the Delaware Basin in Reeves County, Texas.

Consideration for the acquisition will be $160 million in cash, subject to customary purchase price adjustments. The closing of the acquisition is expected to occur on or about May 15, 2017, and is subject to the satisfaction or waiver of certain customary conditions, including the material accuracy of the representations and warranties of Buyer and Sellers, and performance of covenants. The Delaware Basin Orla Acquisition has an effective date of May 1, 2017. The Purchase Agreement contains terms and conditions customary to transactions of this type. Subject to the right of Buyer to be indemnified for certain liabilities for a limited period of time and for breaches of representations, warranties and covenants, Buyer will assume substantially all liabilities associated with the acquired properties. The Purchase Agreement also contains certain customary termination rights for each of Buyer and Sellers.

The properties to be acquired include approximately 4,600 net acres in Reeves County, Texas, consisting of 2,187 net acres adjacent to the Company’s existing operating area in Reeves County and 2,405 net acres in southern Reeves County. In addition, the Company will acquire interests in (i) two operated 4,500 foot lateral horizontal Wolfcamp wells that currently produce approximately 800 net Boe per day, (ii) six operated drilled but uncompleted Wolfcamp wells, four of which have lateral lengths of approximately 4,500 feet and two with approximately 7,500 foot laterals; and (iii) one non-operated 10,000 foot lateral Wolfcamp A well that is currently drilling.

To complete our repositioning as a pure-play Delaware Basin company, Resolute’s board of directors has directed management to explore and take preparatory steps toward a disposition of the Company’s Aneth Field assets. The potential disposition of Aneth Field, if consummated, would provide meaningful additional capital to Resolute. This capital can be deployed either to our Delaware Basin drilling program where we see our highest rates of return or as a component of the optimal long-term financing for the Delaware Basin Orla Acquisition.

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 had been trending lower June 2014 through January 2016, and has been extremely volatile. We expect that volatility to continue. Given the inherent volatility of oil prices, we plan our activities and budget based on product 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 2018. 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 arise only 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 our Permian Basin Properties in 2011, 2012 and 2016. Over that time we have added reserves and production principally through drilling and completion of mid-length to long lateral horizontal wells in the Wolfcamp formation. We acquired the majority of our Aneth Field Properties through two significant purchases from Chevron and ExxonMobil in November 2004 and April 2006, respectively, and Denbury’s interest in the Aneth Field Properties in 2012. Since then 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 also 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 which may include acquisitions of reserves.

At December 31, 2016, we have estimated net proved reserves of approximately 25,005 MBoe that were classified as proved developed non-producing and proved undeveloped, as compared to 7,798 MBoe at December 31, 2015. The largest portion of these reserves is comprised of 17,957 MBoe of reserves added through the addition of twenty immediate offset proved undeveloped Permian locations. Additionally, the 2016 drilling program for the Permian Basin Properties resulted in an addition of proved developed producing reserves of 14,762 MBoe from successful drilling of proved locations.

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 disposal wells and the compressors used for gas compression and supporting 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 affect 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, attorneys, petroleum engineers and other professional advisors, costs associated with public company financial reporting, proxy statements and 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 a financial covenant under our Revolving Credit Facility.

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

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

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with 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 oil prices, cost of services and supplies, economic, political and regulatory developments, competition from other sources of energy and other factors described in this Form 10-K. 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.

2017 Guidance

The following table summarizes our previously announced current financial and operational estimates for 2017. These estimates are subject to the cautionary statements and "Risk Factors" described elsewhere in this Form 10-K.

Projected 2017 production	
Annual MBoe	8,700 - 10,200
Boe per day	24,000 - 28,000
On a revenue-weighted basis:	
Oil	86%
Oil and NGL	90%
On a volume-weighted basis:	
Oil	65%
Oil and NGL	82%
Projected 2017 costs	
Lease operating expense ($ million)	$90 - $105
General and administrative ($ million)	$25 - $29
Projected 2017 capital expenditures ($ million)	$210 - $240

2017 Capital Expenditures. As described in the above-table, Resolute expects to invest between $210 and $240 million in 2017, with 84% focused on Permian Basin development and 9% focused on maintenance spending in Aneth Field. The remaining capital budget will fund corporate level expenditures including land and certain capitalized expense items.

Resolute will evaluate its capital expenditures in relation to its liquidity and 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.

Furthermore, upon closing of the Delaware Basin Orla Acquisition, expected on or about May 15, 2017, and also if a disposition of Aneth Field is completed, Resolute anticipates that it would revise the foregoing guidance to take into account the impact of such transactions on this guidance.

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

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, 2016, in comparison to results for the twelve months ended December 31, 2015 and 2014.

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 2016, 2015 and 2014.

	Twelve Months Ended December 31,		
	2016	2015	2014
Net Sales:			
Oil (MBbl)	3,821	3,271	3,488
Gas (MMcf)	4,811	5,194	5,023
NGL (MBbl)	559	400	320
Total sales (MBoe)	5,182	4,536	4,645
Average daily sales (Boe/day)	14,157	12,427	12,727
Revenue:			
Revenue from oil and gas activities	$164,478	$154,644	$329,371
Operating Expenses:			
Lease operating	$63,699	$79,393	$112,683
Production and ad valorem taxes	16,270	19,985	37,216
General and administrative	32,627	31,447	39,992
General and administrative (excluding non-cash compensation expense)	26,594	19,763	24,494
Restricted cash awards	34,926	1,185	—
Depletion, depreciation, amortization and accretion	50,462	94,338	132,154
Impairment of proved oil and gas properties	58,000	705,000	120,000
Other Income (Expense):			
Interest expense	$(50,684)	$(64,358)	$(31,489)
Commodity derivative instruments gain (loss)	(19,784)	76,492	118,141
Income tax benefit (expense)	(91)	22,354	4,140
Average Sales Prices:			
Oil ($/Bbl)	$38.83	$42.16	$84.28
Gas ($/Mcf)	2.22	2.43	5.23
NGL ($/Bbl)	9.80	10.32	28.58
Average sales price ($/Boe, excluding commodity derivative settlements)	$31.74	$34.09	$70.90
Operating Expenses ($/Boe):			
Lease operating	$12.29	$17.50	$24.26
Production and ad valorem taxes	3.14	4.41	8.01
General and administrative	6.30	6.93	8.61
General and administrative (excluding non-cash	5.13	4.36	5.27

compensation expense)			
Restricted cash awards	6.74	0.26	—
Depletion, depreciation, amortization and accretion	9.74	20.80	28.45

Year Ended December 31, 2016, Compared to the Year Ended December 31, 2015

Revenue. Revenue from oil and gas activities increased to $164.5 million during 2016, from $154.6 million during 2015. Of the $9.9 million increase in revenue, approximately $22.0 million was attributable to increased production, partially offset by $12.1 million of decreased commodity pricing ($31.74 per Boe in 2016 versus $34.09 per Boe in 2015). Sales volumes increased 14% to 5,182 MBoe during 2016 as compared to 4,536 MBoe during 2015. Pro forma for the 2015 property sales, 2016 production increased 50% primarily due to the successful drilling in the Delaware Basin.

Operating Expenses. Lease operating expenses include direct labor, contract services, field office rent, production and ad valorem taxes, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, workover expenses, utilities and other customary charges. Resolute assesses lease operating expenses in part by monitoring the expenses in relation to production volumes and the number of wells operated.

Lease operating expenses decreased to $63.7 million during 2016, from $79.4 million during 2015. On a per-unit basis, lease operating expense decreased 30% to $12.29 per Boe in 2016 from $17.50 per Boe in 2015. The significant decrease in unit operating is due to the combination of lower costs attributable to field operating efficiencies, property sales and the significant increase in production.

Production and ad valorem taxes decreased 19% to $16.3 million during 2016, as compared to $20.0 million during 2015 and were less on a per-unit basis. Production and ad valorem taxes were 10% of total revenue in 2016 and 13% of total revenue in 2015. The lower production and ad valorem taxes as a percentage of revenue in 2016 as compared to 2015 is attributable to ad valorem taxes in Utah that are assessed as of January 1 of each year and which are less responsive to increases in prices after that date than are production taxes assessed on revenue.

General and administrative expenses include the costs of employees and executive officers, related benefits, share-based compensation, office leases, professional fees, general corporate overhead and other costs not directly associated with field operations. We monitor our general and administrative expenses carefully, attempting to balance the cash effect of incurring general and administrative costs against the related benefits, with a focus on hiring and retaining highly qualified staff who can add value to our asset base.

General and administrative expenses increased to $32.6 million during 2016, as compared to $31.4 million during 2015. The $1.2 million, or 4%, increase primarily resulted from $3.1 million in reduced corporate overhead reimbursements due to property sales, $1.4 million in increased professional fees primarily related to a terminated potential senior notes exchange and $1.3 million increase in short term incentive expense offset by decreased share based compensation. On a per-unit basis, general and administrative expenses decreased 9%. Cash-based general and administrative expense was $26.6 million, or $5.13 per Boe in 2016, compared to $19.8 million, or $4.36 per Boe in 2015.

Cash-settled incentive award expense increased to $34.9 million during 2016, as compared to $1.2 million during 2015. This increase was the result of the grant of time-and performance-based restricted cash awards as well as cash-settled stock appreciation rights under the long-term incentive program and the achievement of multiple performance targets that are based on the company’s stock price. The time-based awards will vest and be expensed ratably over three years. The performance-based awards and stock appreciation rights will vest ratably over three years but their fair value will be re-measured at each period end over their ten-year lives. Actual cash payments during the period were $5.7 million.

Depletion, depreciation, amortization and accretion expenses decreased to $50.5 million during 2016, as compared to $94.3 million during 2015. On a per unit basis depreciation, amortization and accretion expenses decreased to $9.74 per Boe in 2016 from $20.80 per Boe in 2015 due the significant increase in proved reserve quantities and a decrease in the 2016 amortization base resulting from the $135 million in ceiling test impairments recorded during the period from October 1, 2015, through March 31, 2016.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. The primary components affecting this calculation are commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. If the net capitalized cost of the Company’s oil and gas properties subject to amortization (the “carrying value”) exceeds the ceiling limitation, the excess is charged to expense. We recorded a $58 million and $705 million non-cash impairment of the carrying value of our proved oil and gas properties during 2016 and 2015, respectively, as a result of the ceiling test limitation. If in future periods a negative impact continues on one or more of the components of the calculation, including market prices of oil and gas (based on a trailing twelve-month unweighted average of the oil and gas prices in effect on the first day of each month), differentials from posted prices, future drilling and capital plans, operating costs or expected production, the Company may incur further full cost ceiling impairment related to its oil and gas properties in such periods.

Other Income (Expense). All of our 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 2016 the loss on oil and gas commodity derivatives was $19.8 million, consisting of $107.8 million of mark-to-market losses partially offset by $88.0 million of derivative settlement gains. During 2015 the gain on oil and gas commodity derivatives was $76.4 million, consisting of $93.1 million of derivative settlement gains offset by $16.7 million of mark-to-market losses.

Interest expense in 2016 decreased to $50.7 million from the $64.4 million recorded in 2015. The $13.7 million or 21% decrease in interest expense was primarily due to a lower level of borrowings on the Revolving Credit Facility and Secured Term Loan Facility offset by lower capitalized interest due to a decrease in unproved property costs with qualifying exploration activity. The components of our interest expense are as follows (in thousands):

	Year Ended December 31,	
	2016	2015
8.50% senior notes	$34,000	$34,000
Secured term loan facility	14,631	20,141
Revolving credit facility	905	4,498
Amortization of deferred financing costs, senior notes premium and secured term loan facility discount	5,240	11,578
Other, net	37	128
Capitalized interest	(4,129)	(5,987)
Total interest expense	$50,684	$64,358

As a result of the prepayment of the Secured Term Loan Facility on January 3, 2017, the Company will recognize $9.9 million of interest costs (comprised of amortization of original issue discount, deferred financing costs and prepayment fees) in the first quarter of 2017.

Income Tax Benefit (Expense). Income tax expense recognized during 2016 was $0.1 million, or 1% of the loss before income taxes in 2016, as compared to income tax benefit of $22.4 million, or 3% of the loss before income taxes in 2015. The significant difference in the 2016 effective rate was attributable to the valuation allowance established in 2015, in addition to noncash executive compensation that is anticipated to be nondeductible for income tax purposes and to permanent differences related to share-based compensation.

Year Ended December 31, 2015, Compared to the Year Ended December 31, 2014

Revenue. Revenue from oil and gas activities decreased to $154.6 million during 2015, from $329.4 million during 2014. Of the $174.7 million decrease in revenue, $167.0 million was attributable to decreased commodity pricing ($34.09 per Boe in 2015 versus $70.90 per Boe in 2014) and $7.8 million was due to decreased production. Sales volumes decreased 2% to 4,536 MBoe during 2015 as compared to 4,645 MBoe during 2014 primarily due to the sale of assets in the Howard, Martin, Midland and Ector counties, Texas, and Campbell County, Wyoming.

Operating Expenses. Lease operating expenses include direct labor, contract services, field office rent, production and ad valorem taxes, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, workover expenses, utilities and other customary charges. Resolute assesses lease operating expenses in part by monitoring the expenses in relation to production volumes and the number of wells operated.

Lease operating expenses decreased to $79.4 million during 2015, from $112.7 million during 2014. The $33.3 million, or 30%, decrease was attributable to reduced spending initiatives driven by depressed commodity pricing. On a unit-of-production basis, lease operating expense decreased 28% to $17.50 per Boe in 2015 from $24.26 per Boe in 2014.

Production and ad valorem taxes decreased 46% to $20.0 million during 2015, as compared to $37.2 million during 2014 and were similarly less on a per-unit basis due to decreased revenue from oil and gas activities. Production and ad valorem taxes were 13% of total revenue in 2015 and 11% of total revenue in 2014. The higher production and ad valorem taxes as a percentage of revenue in 2015 as compared to 2014 is attributable to ad valorem taxes in Utah and Texas that are assessed as of January 1 of each year and which are less responsive to declines in prices after that date than are production taxes assessed on revenue.

General and administrative expenses decreased to $31.4 million during 2015, as compared to $40.0 million during 2014. The $8.5 million, or 21%, decrease primarily resulted from targeted cost reductions associated with salaries, wages and burdens. On a unit-of-production basis, general and administrative expenses decreased 19%. Cash-based general and administrative expense was $19.8 million, or $4.36 per Boe in 2015, compared to $24.5 million, or $5.27 per Boe in 2014. Share-based compensation expense represented $11.7 million, or $2.58 per Boe, during 2015 and $15.5 million, or $3.34 per Boe, during 2014.

Restricted cash award expense was $1.2 million during 2015. There was no related expense during 2014. On a per-unit basis, restricted cash award expense was $0.26 per Boe in 2015. The 2015 expense is a result of the grant of time- and performance-based restricted cash awards under the long-term incentive program. The time-based awards will generally vest and be expensed ratably over three years. The performance-based awards will vest ratably over three years but their fair value will be re-measured at each period end over their ten-year life.

Depletion, depreciation, amortization and accretion expenses decreased to $94.3 million during 2015, as compared to $132.2 million during 2014. The $37.8 million, or 29%, decrease is principally attributable to the lower 2015 amortization base. On a per unit basis depreciation, amortization and accretion expenses decreased to $20.80 per Boe in 2015 from $28.45 per Boe in 2014 due to a decrease in the 2015 amortization base resulting from the $748 million in ceiling test impairments recorded during the period from October 1, 2014, through September 30, 2015, and reduction in future development costs as a result of lower commodity prices.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. The primary components affecting this calculation are commodity prices, reserve quantities added and produced, overall exploration and development costs and depletion expense. If the net capitalized cost of the Company's oil and gas properties subject to amortization (the "carrying value") exceeds the ceiling limitation, the excess is charged to expense. We recorded a $705 million and $120 million non-cash impairment of the carrying value of our proved oil and gas properties during 2015 and 2014, respectively, as a result of the ceiling test limitation. If in future periods a negative impact continues on one or more of the components of the calculation, including market prices of oil and gas (based on a trailing twelve-month unweighted average of the oil and gas prices in effect on the first day of each month), differentials from posted prices, future drilling and capital plans, operating costs or expected production, the Company may incur further full cost ceiling impairment related to its oil and gas properties in such periods.

Other Income (Expense). All of our 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 2015 the gain on oil and gas commodity derivatives was $76.4 million, consisting of $93.1 million of derivative settlement gains and $16.7 million of mark-to-market losses. During 2014 the gain on oil and gas commodity derivatives was $118.1 million, consisting of $123.1 million of mark-to-market gains offset by $5.0 million of derivative settlement losses.

Interest expense in 2015 increased to $64.4 million from the $31.5 million recorded in 2014. The $32.9 million or 104% increase in interest expense was primarily due to higher interest rates associated with the Secured Term Loan Facility entered into on December 30, 2014, as well as lower capitalized interest due to decreased exploration activity. The components of our interest expense are as follows (in thousands):

	Year Ended December 31,	
	2015	2014
8.50% senior notes	$34,000	$34,000
Secured term loan facility	20,141	—
Revolving credit facility	4,498	10,196
Amortization of deferred financing costs and senior notes premium	11,578	2,337
Other, net	128	(104)
Capitalized interest	(5,987)	(14,940)
Total interest expense	$64,358	$31,489

Income Tax Benefit (Expense). Income tax benefit recognized during 2015 was $22.4 million or 3% of the loss before income taxes in 2015, as compared to income tax benefit of $4.1 million, or 16% of the loss before income taxes in 2014. The lower 2015 effective rate was attributable to the valuation allowance that was established during 2015, in addition to noncash executive compensation that is anticipated to be nondeductible for income tax purposes and to permanent differences related to share-based compensation.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash generated from operations, amounts available under our Revolving Credit Facility and our Secured Term Loan Facility, and 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, 2016, 2015 and 2014.

	Year Ended December 31,		
	2016	2015	2014
	(in thousands)		
Net cash provided by operating activities	$83,719	$69,479	$143,468
Net cash provided by (used in) investing activities	(190,467)	199,583	(175,893)
Net cash provided by (used in) financing activities	230,540	(264,117)	36,758

Net cash provided by operating activities was $83.7 million during 2016 as compared to $69.5 million during 2015 and $143.5 million during 2014. The increase in net cash provided by operating activities in 2016 over 2015 was primarily due to increased revenue resulting from increased production in 2016 offset by reduced cash flow driven by 2015 property sales and increased general and administrative costs. The decrease in 2015 over 2014 was primarily due to decreased revenue resulted from lower commodity prices.

Net cash used in investing activities was $190.5 million during 2016 as compared to $199.6 million provided during 2015 and $175.9 million used during 2014. The primary investing activity in 2016 was cash used for capital expenditures of $188.8 million. Capital expenditures in the Permian Basin consisted primarily of $95.9 in acquisitions and $111.2 million in drilling and infrastructure projects, partially offset by $35.5 million of net proceeds primarily from the sale of the Reeves County midstream assets. Capital expenditures in Aneth Field consisted of $5.9 million in CO_2 acquisition and $11.3 million in compression and facility projects. The primary investing activity in 2015 was cash provided by asset sales of $269.0 million. Capital expenditures consisted primarily of $8.9 million in CO_2 acquisition and $23.0 million in drilling activities and infrastructure projects in the Permian Basin of west Texas. Capital divestitures primarily included $42.0 million of net proceeds from the sale of the Howard and Martin County properties in the Permian Basin, $54.0 million of net proceeds from the sale of our Hilight Field properties in the Powder River Basin and $175.0 million of net proceeds from the sale of our Gardendale properties in the Midland Basin. 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 net proceeds from the sale of certain interests in the Delaware Basin.

Net cash provided by financing activities was $230.5 million in 2016 as compared to net cash used of $264.1 million in 2015 and net cash provided of $36.8 million in 2014. The primary financing activities in 2016 were our December 2016 common stock offering ($160.9 million in net cash provided) and our preferred stock offering in October 2016 ($59.7 million of net cash provided), partially offset by $10 million in net borrowings under the Revolving Credit Facility. The primary financing activities in 2015 were $235 million in net repayment of borrowings under the Revolving Credit Facility and $71.7 million in Secured Term Loan Facility principal payment offset by $46.5 million in net proceeds from the issuance of the Incremental Term Loans under the Secured Term Loan Facility.

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 other debt or equity securities or from other sources, such as asset sales. 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 or Senior Notes. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to satisfy our obligations under our existing indebtedness, finance the capital expenditures necessary to maintain production or proved reserves or complete acquisitions that may be favorable to us.

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 Revolving Credit Facility to fund our operations.

Revolving Credit Facility

Our prior Revolving Credit Facility was with a syndicate of banks. On February 17, 2017, we entered into the Third Amended and Restated Credit Agreement (refer to Note 12) and as a result, the syndicate banks are now led by Bank of Montreal, as Administrative Agent, Capital One, National Association, as syndication agent, and Barclays Bank PLC, ING Capital LLC and SunTrust Bank, as co-documentation agents. The Revolving Credit Facility specifies a maximum borrowing base as determined by the lenders in their sole discretion which has initially been set at $150 million. 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 re-determined semi-annually, and the amount available for borrowing could be increased or decreased as a result of such redeterminations. Under certain circumstances, either the Company or the lenders may request an interim redetermination. The Revolving Credit Facility matures in February 2021 unless there is a maturity of material indebtedness prior to such date.

The Revolving Credit Facility includes covenants that require, among other things, that we maintain a ratio of current assets to current liabilities of no less than 1.0 to 1.0 and a ratio of funded debt to EBITDA of no more than 4.0 to 1.0. The Revolving Credit Facility prohibits us from entering into derivative arrangements for more than (i) 85% of our anticipated production from proved properties in the next two years and (ii) the greater of 75% of our anticipated production from proved properties or 85% of our production from projected proved developed producing properties after such two year period (not to exceed a term of 60 months for any such derivative arrangement). The Revolving Credit Facility also includes customary additional terms and covenants that place limitations on certain types of activities, the payment of dividends, and that require satisfaction of certain financial tests.

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 and Resolute Natural Resources Southwest, LLC, which are wholly-owned subsidiaries of the Company.

Each borrowing under the Revolving Credit Facility accrues interest at either (a) the London Interbank Offered Rate ("LIBOR"), plus a margin that ranges from 3.0% to 4.0% or (b) the Alternate 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 LIBOR, plus a margin for the Alternate Base Rate that ranges from 2.0% to 3.0%. Each such margin is based on the level of utilization under the borrowing base.

We were in compliance with all material terms and covenants of the Revolving Credit Facility at December 31, 2016.

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 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. Initial funding of the Secured Term Loan Facility occurred on December 31, 2014, with net proceeds of approximately $135 million after payment of transaction-related fees, expenses and discounts. Net proceeds were used to repay amounts outstanding under the Revolving Credit Facility. The Secured Term Loan Facility had a maturity date six months after the maturity of our existing Revolving Credit Facility, but in no event later than November 1, 2019.

On May 18, 2015, Resolute and certain of its subsidiaries, as guarantors, entered into an Amendment to the Secured Term Loan Agreement and Increased Facility Activation Notice-Incremental Term Loans with Bank of Montreal, as administrative agent, and the lenders party thereto, pursuant to which the Company borrowed an additional $50 million of Incremental Term Loans under its Secured Term Loan Agreement dated December 30, 2014. Funding of the Incremental Term Loans occurred on May 19, 2015. The Incremental Term Loans had the same terms as the existing second lien borrowings under the Secured Term Loan Agreement, adjusted for the date of the closing. The $50 million of Incremental Term Loans was placed with the same lenders that participated in the initial $150 million second lien closing in December 2014. Net proceeds from the Incremental Term Loans, of approximately $46 million after payment of transaction-related fees, expenses and discounts, were used to repay amounts outstanding under the Revolving Credit Facility.

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

We were in compliance with all material terms and covenants of the secured term loan facility at December 31, 2016.

During December 2015, the Company retired $70 million of the amount outstanding under the Secured Term Loan Facility following the sale of our Gardendale properties in Midland Basin on December 22, 2015. Finally, on January 3, 2017, we paid approximately $132 million constituting all amounts due under the Secured Term Loan Facility (including prepayment fees), with a portion of the proceeds from the previously announced common stock offering that closed on December 23, 2016. The Secured Term Loan Facility was terminated in connection with the repayment.

Senior Notes

In 2012 we consummated two private placements of senior notes with principal totaling $400 million. The Senior Notes are due May 1, 2020, and bear an annual interest rate of 8.50% with the interest on the notes 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 and our existing subsidiaries (the “Guarantors”) 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 Senior Notes for publically registered Senior 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 certain types of 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 material terms and covenants under our Senior Notes as of December 31, 2016.

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 not less than 30 or more than 60 days prior notice, at redemption prices set forth in the Indenture. If a change of control occurs, each holder of the Senior Notes will have the right to require that we purchase all of such holder’s Senior Notes in an amount equal to 101% of the principal of such Senior Notes, plus accrued and unpaid interest, if any, to the date of the purchase.

Preferred Stock

On October 4, 2016, the Company entered into a Purchase Agreement (the “Preferred Stock Purchase Agreement”) with BMO Capital Markets Corp. (“Initial Purchaser”), pursuant to which the Company agreed to issue and sell to Initial Purchaser 55,000 shares (the “Firm Securities”) of the Company’s 8 % Series B Cumulative Perpetual Convertible Preferred Stock, par value $0.0001 per share (the “Convertible Preferred Stock”) and, at Initial Purchaser’s option, up to 7,500 additional shares of Convertible Preferred Stock (together with the Firm Securities, collectively, the “Securities”).

On October 6, 2016, Initial Purchaser exercised its over-allotment option to purchase the additional 7,500 shares of Convertible Preferred Stock in full, bringing the total shares of Convertible Preferred Stock purchased by Initial Purchaser to 62,500, for an aggregate net consideration of $60 million, before offering expenses.

Each holder has the right at any time, at its option, to convert, any or all of such holder’s shares of Convertible Preferred Stock at an initial conversion rate of 33.8616 shares of fully paid and nonassessable shares of Common Stock, per share of Convertible Preferred Stock. Additionally, at any time on or after October 15, 2021, the Company shall have the right, at its option, to elect to cause all, and not part, of the outstanding shares of Convertible Preferred Stock to be automatically converted into that number of shares of Common Stock for each share of Convertible Preferred Stock equal to the conversion rate in effect on the mandatory conversion date as such terms are defined in the Certificate of Designation.

As of December 31, 2016, the Company had accumulated preferred dividends of $1.2 million. A total dividend of $1.4 million was declared on January 15, 2017 and paid on January 17, 2017.

Commitment Letter

The Company is evaluating the optimal financing for the Delaware Basin Orla Acquisition, and anticipates that the ultimate financing may have components of long-term debt and equity. In the interim, however, the Company entered into a commitment letter on March 3, 2017, for a $100 million unsecured bridge financing facility with BMO Capital Markets (the “Commitment Letter”). The Commitment Letter provides the Company with the ability to borrow up to $100 million, subject to satisfaction or waiver of customary conditions to closing, for the consummation of the Delaware Basin Orla Acquisition. In the event that the Bridge Commitment is not drawn in connection with the Delaware Basin Orla Acquisition, then the obligations of the parties under the Commitment Letter terminate. Together with borrowing availability under the Company’s Revolving Credit Facility, the bridge facility allows the Company to close the acquisition without an immediate long-term debt or equity issuance.

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 have the following contractual obligations and commitments for the next five years as of December 31, 2016:

	Less than 1 year	1-3 Years	3–5 Years	More Than 5 Years	Total [6]
	(in thousands)				
Obligations:					
Term loans and related interest [7]	$166,013	$68,000	$417,000	$ —	$651,013
Revolving credit facility [1]	10,000	—	—	—	10,000
Office and equipment leases	1,892	3,021	2,588	550	8,051
Operating equipment leases [2]	1,629	—	—	—	1,629
Vehicle leases	383	75	—	—	458
ExxonMobil escrow agreement [3]	289	578	578	3,044	4,489
Construction purchase obligations [4]	1,573	—	—	—	1,573
CO_2 purchases [5]	5,671	5,671	—	—	11,342
Total	$187,450	$77,345	$420,166	$ 3,594	$688,555

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, 2016, related to construction projects in the Permian Basin 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, 2016.
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.
7) Included in the balance due in less than 1 year is $132 million, which was repaid on January 3, 2017. This amount constitutes the balance due under the Secured Term Loan Facility. The Secured Term Loan Facility was terminated in connection with the repayment.

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.

Long-term Incentive 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). Cash-settled incentive award expense is measured quarterly using a cash-or-nothing valuation model. The Company estimates forfeitures in calculating the cost related to share-based compensation and cash-settled incentive awards expense 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.

Recent Accounting Pronouncements

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, which creates Topic 606 (“ASC 606”). ASC 606 supersedes existing revenue recognition requirements under GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which we expect to be entitled in exchange for transferring goods or services to a customer. Additional disclosures will be required as to the nature, timing and uncertainty of revenue and cash flows from contracts with customers. In August 2015, the FASB issued ASU 2015-14, which defers the effective date of ASU 2014-09 for one year to annual reports beginning after December 15, 2017. Early adoption is permitted for fiscal years beginning after December 15, 2016.

In May 2016, the FASB issued ASU 2016-12: Revenue from Contracts with Customers (Topic 606): Narrow Scope Improvements and Practical Expedients (“ASU 2016-12”), which updates ASU 2014-09 to clarify core recognition principles including collectability, sales tax presentation, noncash consideration, contract modifications and completed contracts at transition. This ASU is required to be adopted using either the retrospective transition method, which requires restating previously reported results or the cumulative effect (modified retrospective) transition method, which utilizes a cumulative-effect adjustment retained earnings in the period of adoption to account for the prior period effects. We have aggregated and reviewed our contracts that are within the scope of ASC 606. Based on our evaluation to date, there will not be a material impact on our financial statements. However, we anticipate the new standard will result in more robust footnote disclosures. We cannot currently determine the extent of the new footnote disclosures as further clarification is needed for certain practices common to the industry. We will continue to evaluate the impacts that future contracts may have.

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, as amended and restated on February 17, 2017, the form of derivative instruments to be entered into is at our discretion, but they are 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 after such two year period, 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.

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, 2016, the fair value of our commodity derivatives was a net liability of $11.9 million.

The following table represents our oil swap contracts as of December 31, 2016:

	Oil (NYMEX WTI)		
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2017	1,528	$ 51.10	$ (2,748)

The following table represents our gas swap contracts as of December 31, 2016:

	Gas (NYMEX Henry Hub)		
Remaining Term	MMBtu per Day	Weighted Average Swap Price per MMBtu	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2017	2,008	$ 2.807	$ (627)

The following table represents our NGL swap contracts as of December 31, 2016:

	NGL (Mont Belvieu)		
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2017	300	$ 19.53	$ (548)

The following table represents our two-way oil collar contracts as of December 31, 2016:

	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 2017	3,684	$ 46.80	$ 57.63	$ (1,994)

The following table represents our two-way gas collar contracts as of December 31, 2016:

	Gas (NYMEX Henry Hub)			
Remaining Term	MMBtu per Day	Weighted Average Floor Price per MMBtu	Weighted Average Floor Price per MMBtu	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2017	8,080	$ 2.566	$ 3.433	$ (1,227)

The following table represents our three-way oil collar contracts as of December 31, 2016:

	Oil (NYMEX WTI)				
Remaining Term	Bbl per Day	Weighted Average Short Put Price per Bbl	Weighted Average Floor Price per Bbl	Weighted Average Ceiling Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2017	1,130	$ 40.00	$ 50.00	$ 60.10	$ (570)

The following table represents our three-way gas collar contracts as of December 31, 2016:

	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 – Dec 2017	1,505	$ 2.692	$ 3.192	$ 3.746	$ (82)

The following represents our oil call contract as of December 31, 2016:

	Oil (NYMEX WTI)		
Remaining Term	Sold Put Bbl per Day	Weighted Average Sold Put Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Mar – Dec 2015	1,100	$ 50.00	$ (4,104)

73

Subsequent to December 31, 2016, we entered into additional commodity derivative contracts as summarized below:

	Oil (NYMEX WTI)	
Commodity Swap	Bbl per Day	Weighted Average Swap Price per Bbl
Apr – Jun 2017	1,000	$ 55.45
Jul – Dec 2017	1,000	$ 56.30
Jul – Dec 2017	1,000	$ 56.50

Interest Rate Risk

At December 31, 2016, we had $10.0 million and $128.3 million of outstanding debt under the Revolving Credit Facility and Secured Term Loan Facility, respectively. Interest is calculated under the terms of the agreement based principally on a LIBOR spread. A 10% increase in LIBOR would result in an increase less than $0.1 million 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 current or former 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 contracts known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. Master Agreement (“ISDA”). 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, 2016. 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, 2016, 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, 2016, and has concluded that the Company maintained effective internal control over financial reporting as of December 31, 2016. 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 2016 annual stockholders’ meeting and is incorporated by reference in this report.

ITEM 11. EXECUTIVE COMPENSATION

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2016 annual stockholders’ meeting and is incorporated by reference in this report.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2016 annual stockholders’ meeting and is incorporated by reference in this report.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2016 annual stockholders’ meeting and is incorporated by reference in this report.

ITEM 14. PRINCIPAL ACCOUNTING FEE AND SERVICES

Information relating to this item will be included in an amendment to this report or in the proxy statement for our 2016 annual stockholders’ meeting and is incorporated by reference in this report.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES
See "Index to Consolidated Financial Statements" on page F-1.

Exhibit Number	Description of Exhibits
2.1†	Purchase and IPO Reorganization Agreement, dated as of August 2, 2009, among Hicks Acquisition Company I, Inc., Resolute Energy Corporation, Resolute Subsidiary Corporation., Resolute Holdings, LLC, Resolute Holdings Sub, LLC, Resolute Aneth, LLC and HH-HACI, L.P., (incorporated by reference to Annex A to the Registration Statement on Form S-4 filed with the SEC on August 6, 2009 (File. No 33-161076)("Initial S-4")).
2.2	Letter Agreement amending Purchase and IPO Reorganization Agreement, dated as of September 9, 2009, among Hicks Acquisition Company I, Inc., Resolute Energy Corporation, Resolute Subsidiary Corporation., Resolute Holdings, LLC, Resolute Holdings Sub, LLC, Resolute Aneth, LLC and HH-HACI, L.P., (incorporated by reference to Annex A to the Initial S-4).
2.3†	Purchase and Sale Agreement between Exxon Mobil Corporation, ExxonMobil Oil Corporation, Mobil Exploration and Producing North America Inc., Mobil Producing Texas & New Mexico Inc. and Mobil Exploration & Producing U.S. Inc. and Resolute Aneth, LLC — 75% and Navajo Nation Oil and Gas Company — 25% dated January 1, 2005 (incorporated by reference to Exhibit 2.2 to the Initial S-4).
2.4†	Asset Sale Agreement Aneth Unit, Ratherford Unit and McElmo Creek Unit, San Juan County, Utah between Chevron U.S.A. Inc. (as seller) and Resolute Natural Resources Company and Navajo Nation Oil and Gas Company, Inc. (as buyer) dated October 22, 2004 (incorporated by reference to Exhibit 2.3 to the Initial S-4).
2.5†	Stock Purchase Agreement dated June 24, 2008, between Primary Natural Resources, Inc. (as seller) and Resolute Acquisition Company, LLC (as buyer) (incorporated by reference to Exhibit 2.4 to the Initial S-4).
2.6†	Purchase and Sale Agreement between Celero Energy II, LP and Caprock Land & Cattle, LLC, as sellers, Resolute Natural Resources Southwest, LLC, as buyer, and Resolute Energy Corporation, as guarantor, dated December 1, 2012 (incorporated by reference to Exhibit 2.1 to the current report on Form 8-K filed on December 5, 2012).
2.6.1	

	Amendment to Purchase and Sale Agreement, by and among Celero Energy II, LP and Caprock Land & Cattle, LLC, as Sellers, Resolute Natural Resources Southwest, LLC, as Buyer, and Resolute Energy Corporation, as Guarantor, dated December 21, 2012 (incorporated by reference to Exhibit 2.1 to the current report on Form 8-K filed on December 26, 2012).
2.7†	Purchase, Sale and Option Agreement dated December 28, 2012, by and among RSP Permian LLC, Wallace Family Partnership, LP, and Ted Collins, Jr., as Sellers, and Resolute Natural Resources Southwest, LLC, as Buyer (incorporated by reference to Exhibit 2.1 to the current report on Form 8-K filed on December 31, 2012).
2.8	Purchase and Sale Agreement dated November 19, 2015, by and between Resolute Natural Resources Southwest, LLC, as seller and Independence Resources Holdings, LLC, as buyer (incorporated by reference to Exhibit 2.1 to the Form 8-K filed on December 29, 2015 and amended on March 8, 2016).
2.9	Purchase and Sale Agreement, dated October 4, 2016, among Resolute Energy Corporation, Resolute Natural Resources Southwest, LLC and Firewheel Energy, LLC (incorporated by reference to Exhibit 2.1 to the Form 8-K filed on October 7, 2016).
3.1	Amended and Restated Certificate of Incorporation of Resolute Energy Corporation, filed September 25, 2009 (incorporated by reference to Exhibit 3.1 to the Annual Report on Form 10-K of Resolute Energy Corporation filed on March 30, 2010).
3.2	