Resolute Energy Corp
Form 10-Q
November 06, 2017
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2017

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File No. 001-34464

RESOLUTE ENERGY CORPORATION

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or other Jurisdiction of	27-0659371 (I.R.S. Employer
Incorporation or Organization)	Identification Number)
1700 Lincoln Street, Suite 2800 Denver, CO (Address of Principal Executive Offices)	80203 (Zip Code)

(303) 534-4600

(Registrant’s telephone number, including area code)

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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer		Accelerated filer
Non-accelerated filer	(Do not check if a small reporting company)	Smaller reporting company
Emerging growth company		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

As of October 31, 2017, 22,503,907 shares of the Registrant's $0.0001 par value Common Stock were outstanding.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q 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; anticipated production in 2017; anticipated gas to oil ratios in 2017; anticipated capital expenditures and activity in 2017, including our 2017 expanded capital plan; our financial condition and management of the Company in the current commodity price environment, including expectations regarding price fluctuations; future financial and operating results; liquidity and availability of capital; future borrowing base adjustments and the effect thereof; future pad drilling plans and expected resulting cost savings and production impact; future production, reserve growth and decline rates; our plans and expectations regarding our development activities including drilling and completing wells, the number of such potential projects, locations, and anticipated acreage held by production by the end of 2017; the potential impact of well interference and the effectiveness of operational adjustments to mitigate it; the prospectivity of our properties and acreage; the expected benefits of the Aneth Disposition (defined below); 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. 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, if any, in our Annual Report on Form 10-K for the year ended December 31, 2016, and such things as:

- 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;
- our ability to achieve the growth and benefits we expect from our acquisitions;
- our ability to achieve the benefits we expect from the disposition of Aneth Field;
- the success of the development plan for and production from our oil and gas properties;
- the completion, timing and success of drilling on our properties;
- the timing and amount of future production of oil and gas;
- 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, which 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;
- 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;
- risks associated with rising interest rates;
- inaccuracies in reserve estimates;
- 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;

- the impact of any U.S. or global economic recession;
- the ability to sell or otherwise monetize 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;
- the concentration of our credit risk as the result of depending on one primary oil purchaser and one primary gas purchaser in the Delaware Basin;
- 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, 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 single geographic area;
- 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;
- potential changes in income tax deductions 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 disruptions or 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 gathering and compression infrastructure;
- 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 rates 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 Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2016, in particular the factors described under "Risk Factors."

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RESOLUTE ENERGY CORPORATION

Condensed Consolidated Balance Sheets (Unaudited)

(in thousands, except share amounts)

	September 30, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$888	$ 133,089
Accounts receivable	73,830	55,228
Commodity derivative instruments	1,653	218
Prepaid expenses and other current assets	1,911	3,249
Total current assets	78,282	191,784
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting		
Unproved	254,865	121,375
Proved	2,132,497	1,889,111
Other property and equipment	13,271	9,754
Accumulated depletion, depreciation and amortization	(1,709,800)	(1,647,120)
Net property and equipment	690,833	373,120
Other assets:		
Restricted cash	23,195	23,137
Other assets	10	332
Total assets	$792,320	$ 588,373
Liabilities and Stockholders' Deficit		
Current liabilities:		
Accounts payable	$27,123	$ 8,675
Accrued expenses	71,873	37,507
Accrued revenue payable	33,219	19,801
Accrued cash-settled incentive awards	27,278	27,158
Accrued interest payable	18,651	5,784
Asset retirement obligations	1,216	895
Commodity derivative instruments	8,177	8,014
Secured term loan facility	—	122,139
Total current liabilities	187,537	229,973
Long term liabilities:		
Revolving credit facility	122,185	8,821
Senior notes	523,008	397,154
Asset retirement obligations	17,230	19,457
Commodity derivative instruments	4,557	4,104
Other long term liabilities	11,568	4,611
Total liabilities	866,085	664,120
Commitments and contingencies (See Note 10)		
Stockholders' deficit:		
Convertible preferred stock, $0.0001 par value; 1,000,000 shares authorized; issued and outstanding 62,500 shares at September 30, 2017 and December 31, 2016;	—	—

$62.5 million liquidation preference		
Common stock, $0.0001 par value; 45,000,000 shares authorized; issued and outstanding		
22,494,040 and 21,932,842 shares at September 30, 2017 and December 31, 2016, respectively	2	2
Additional paid-in capital	954,198	948,380
Accumulated deficit	(1,027,965)	(1,024,129)
Total stockholders' deficit	(73,765)	(75,747)
Total liabilities and stockholders' deficit	$792,320	$588,373

See notes to condensed consolidated financial statements

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RESOLUTE ENERGY CORPORATION

Condensed Consolidated Statements of Operations (Unaudited)

(in thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenue:				
Oil	$67,665	$42,394	$186,027	$93,672
Gas	8,805	3,574	20,978	5,761
Natural gas liquids	5,082	1,451	10,799	2,377
Total revenue	81,552	47,419	217,804	101,810
Operating expenses:				
Lease operating	25,093	16,572	63,339	46,078
Production and ad valorem taxes	8,767	4,839	21,701	12,229
Depletion, depreciation, amortization, and asset retirement obligation accretion	25,521	12,474	63,889	33,700
Impairment of proved oil and gas properties	—	—	—	58,000
General and administrative	9,546	7,161	29,433	23,659
Cash-settled incentive awards	4,996	16,043	9,010	18,275
Total operating expenses	73,923	57,089	187,372	191,941
Income (loss) from operations	7,629	(9,670)	30,432	(90,131)
Other income (expense):				
Interest expense, net	(8,527)	(13,272)	(35,003)	(39,330)
Commodity derivative instruments gain (loss)	(13,719)	3,972	4,579	(11,739)
Other income (expense)	(13)	114	63	126
Total other expense	(22,259)	(9,186)	(30,361)	(50,943)
Income (loss) before income taxes	(14,630)	(18,856)	71	(141,074)
Income tax benefit	28	—	28	—
Net income (loss)	(14,602)	(18,856)	99	(141,074)
Preferred stock dividends	—	—	(3,935)	—
Net loss available to common shareholders	$(14,602)	$(18,856)	$(3,836)	$(141,074)
Net loss per common share:				
Basic and diluted	$(0.71)	$(1.24)	$(0.22)	$(9.33)
Weighted average common shares outstanding:				
Basic and diluted	21,941	15,173	21,866	15,122

See notes to condensed consolidated financial statements

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RESOLUTE ENERGY CORPORATION

Condensed Consolidated Statements of Stockholders' Deficit (Unaudited)

(in thousands)

	Common Stock Shares	Common Stock Amount	Preferred Stock Shares	Preferred Stock Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Deficit
Balance as of January 1, 2017	21,933	$ 2	63	$ —	$ 948,380	$ (1,024,129)	$ (75,747)
Issuance of stock, restricted stock and share-based compensation	581	—	—	—	8,969	—	8,969
Redemption of restricted stock for employee income tax and restricted stock forfeitures	(93)	—	—	—	(3,393)	—	(3,393)
Exercise of employee options to purchase common stock	73	—	—	—	242	—	242
Preferred stock dividend	—	—	—	—	—	(3,935)	(3,935)
Net income	—	—	—	—	—	99	99
Balance as of September 30, 2017	22,494	$ 2	63	$ —	$ 954,198	$ (1,027,965)	$ (73,765)

See notes to condensed consolidated financial statements

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RESOLUTE ENERGY CORPORATION

Condensed Consolidated Statements of Cash Flows (Unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2017	2016
Operating activities:		
Net income (loss)	$99	$(141,074)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and asset retirement obligation accretion	63,889	33,700
Impairment of proved oil and gas properties	—	58,000
Amortization of deferred financing costs and long-term debt premium and discount	8,801	3,922
Share-based compensation	8,952	5,143
Commodity derivative instruments (gain) loss	(4,579)	11,739
Commodity derivative settlement gain	3,760	69,649
Change in operating assets and liabilities:		
Accounts receivable	(12,541)	(9,970)
Other current assets	(632)	(430)
Accounts payable and accrued expenses	31,334	19,416
Accrued interest payable	12,867	8,600
Net cash provided by operating activities	111,950	58,695
Investing activities:		
Oil and gas exploration and development expenditures	(218,972)	(98,313)
Purchase of oil and gas properties	(161,264)	—
Proceeds from sale of oil and gas properties	28,439	32,962
Deposit for Aneth disposition	10,000	—
Purchase of other property and equipment	(3,517)	(106)
Restricted cash	(58)	(1,640)
Other long-term assets	31	38
Net cash used in investing activities	(345,341)	(67,059)
Financing activities:		
Proceeds from bank borrowings	291,000	73,500
Repayments of borrowings	(176,000)	(73,500)
Proceeds from issuance of senior notes	126,875	—
Repayment of term loan	(128,303)	—
Payment of financing costs	(5,296)	—
Payment of preferred dividend	(3,935)	—
Redemption of restricted stock for employee income taxes	(3,393)	(73)
Proceeds from exercise of employee options to purchase common stock	242	48
Net cash provided by (used in) financing activities	101,190	(25)
Net decrease in cash and cash equivalents	(132,201)	(8,389)
Cash and cash equivalents at beginning of period	133,089	9,297
Cash and cash equivalents at end of period	$888	$908

See notes to condensed consolidated financial statements

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RESOLUTE ENERGY CORPORATION

Notes to Condensed Consolidated Financial Statements

Note 1 — Organization and Nature of Business

Resolute Energy Corporation ("Resolute" or the "Company"), is an independent oil and gas company engaged in the exploitation, development, exploration for and acquisition of oil and gas properties. The Company's operating assets are comprised of properties in the Delaware Basin in west Texas (the "Delaware Basin Properties") and Aneth Field located in the Paradox Basin in southeast Utah (the "Aneth Field Properties" or "Aneth Field"). As discussed in Note 11, the Company closed on the disposition of Aneth Field on November 6, 2017. All periods presented include the results related to Aneth Field. The Company conducts all of its activities in the United States of America.

Resolute Energy Corporation, the stand-alone parent entity, has insignificant independent assets and no operations. Its guarantees are full and unconditional and joint and several, and there are no subsidiaries of the parent company other than the Guarantors (defined below). There are no restrictions on the Company's ability to obtain cash dividends or other distributions of funds from its subsidiaries, except those imposed by applicable law.

Note 2 — Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

The unaudited condensed consolidated financial statements include Resolute and its subsidiaries, and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and Regulation S-X for interim financial reporting. Except as disclosed herein, there has been no material change in our basis of presentation from the information disclosed in the notes to Resolute's consolidated financial statements for the year ended December 31, 2016. In the opinion of management, all adjustments consisting of normal recurring accruals considered necessary for a fair presentation of the interim financial information have been included. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year. All intercompany transactions have been eliminated upon consolidation. Certain prior period amounts have been reclassified to conform to the current period presentation.

In connection with the preparation of the condensed consolidated financial statements, Resolute evaluated subsequent events that occurred after the balance sheet date, through the date of filing. See Note 11.

Significant Accounting Policies

The significant accounting policies followed by Resolute are set forth in Resolute's consolidated financial statements for the year ended December 31, 2016. These unaudited condensed consolidated financial statements are to be read in conjunction with the consolidated financial statements appearing in Resolute's Annual Report on Form 10-K and related notes for the year ended December 31, 2016.

Recent Accounting Pronouncements

In January 2017 the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business, which clarifies the definition of a business to assist entities with evaluating when a set of transferred assets and activities is deemed to be a business. Determining whether a transferred set constitutes a business is important because the accounting for a business combination differs from that of an asset acquisition. The definition of a business also affects the accounting for dispositions. Under the new standard, when substantially all of the fair value of assets acquired is concentrated in a single asset, or a group of similar assets, the assets acquired would not represent a business and business combination accounting would not be required. The standard is effective for interim and annual periods beginning after December 15, 2017 and shall be applied prospectively. Early adoption is permitted. The Company elected to early adopt this standard in the second quarter of 2017.

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 to retained earnings in the period of adoption to account for the prior period effects. The Company has not yet selected a transition method, but expects that it will use the cumulative effect method. 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.

In February 2016 the FASB issued ASU 2016-02: Leases (Topic 842), which requires that lessees recognize both a lease liability and a right-of-use asset at the commencement date. This authoritative accounting guidance is effective for the annual period beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2018. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

Assumptions, Judgments and Estimates

The preparation of the condensed consolidated financial statements in conformity with GAAP requires management to make various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenue and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events. Accordingly, actual results could differ from amounts previously established.

Significant estimates with regard to the condensed consolidated financial statements include proved oil and gas reserve volumes and the related present value of estimated future net cash flows used in the ceiling test applied to capitalized oil and gas properties; asset retirement obligations; valuation of derivative assets and liabilities; the estimated fair value and allocation of the purchase price related to business combinations; share-based compensation expense; cash-settled long-term incentive expense; depletion, depreciation and amortization; accrued liabilities; revenue and related receivables and income taxes.

Accounts Receivable

The Company's accounts receivable consist of the following as of the dates indicated (in thousands):

	September 30, 2017	December 31, 2016
Trade receivables	$ 21,452	$ 14,898
Revenue receivables	45,048	32,817
Derivative receivables	434	5,695
Other receivables	6,896	1,818
Total accounts receivable	$ 73,830	$ 55,228

The Company's accounts receivable consist mainly of receivables from oil, gas, and natural gas liquids ("NGL") purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. Generally, the Company's oil and gas receivables are due within fifteen days and are collected in less than two months, and the Company historically has had limited receivables that were not collected.

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. As of September 30, 2017 and December 31, 2016, the Company had no allowance for doubtful accounts recorded.

Oil and Gas Properties

Pursuant to full cost accounting rules, Resolute is required to perform a quarterly “ceiling test” calculation to test its oil and gas properties for possible impairment. The primary components impacting the calculation are commodity prices, reserve quantities and associated production, 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 would be charged to expense. The ceiling limitation is equal to the sum of the present value discounted at 10% of estimated future net cash flows from proved reserves, the cost of properties not being amortized, the lower of cost or estimated fair value of unproven properties included in the costs being amortized, and all related income tax effects.

No impairment was recorded for the three and nine months ended September 30, 2017. For the three and nine months ended September 30, 2016, the Company recorded non-cash impairments of its oil and gas properties of $0 and $58 million, respectively, as a result of the ceiling test limitation. If in future periods a negative factor impacts 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.

Note 3 — Acquisitions and Divestitures

Acquisition of Reeves County Properties in the Delaware Basin

Delaware Basin Bronco Acquisition

On March 3, 2017, Resolute Natural Resources Southwest, LLC (“Resolute Southwest”), a wholly owned subsidiary of the Company, entered into a Purchase and Sale Agreement with CP Exploration II, LLC and Petrocap CPX, LLC pursuant to which Resolute Southwest agreed to acquire certain undeveloped and developed oil and gas properties in the Delaware Basin in Reeves County, Texas (the “Delaware Basin Bronco Acquisition”). The closing of the Delaware Basin Bronco Acquisition occurred on May 15, 2017, with an effective date of May 1, 2017.

The acquisition was accounted for as an asset acquisition, and therefore, the properties were recorded based on the fair value of the total consideration transferred on the acquisition date and transaction costs were capitalized as a component of the cost of the assets acquired. The Company acquired these properties for $161.3 million, which it financed substantially with proceeds received from the offering of $125 million of 8.50% Senior Notes due 2020 (as defined in Note 5) that closed in May 2017. The Company recorded $144.8 million of the total consideration transferred as unproved oil and gas property.

The properties acquired include approximately 4,600 net acres in Reeves County, Texas (the “Bronco Assets”), which were considered predominantly unproved, 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.

Delaware Basin Firewheel Acquisition

In October 2016 Resolute and Resolute Southwest entered into a Purchase and Sale Agreement with Firewheel Energy, LLC (“Firewheel”) pursuant to which Resolute Southwest agreed to acquire certain oil and gas interests in the Delaware Basin in Reeves County, Texas (the “Firewheel Properties”), for consideration to Firewheel 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 upon the closing of the purchase of the Firewheel Properties (the “Delaware Basin Firewheel Acquisition”). The closing of the Delaware Basin Firewheel Acquisition occurred on October 7, 2016.

The Company acquired the Firewheel Properties for $153.2 million. Revenue and expenses related to the acquired properties are included in the consolidated statement of operations on the closing date of the transaction. The Delaware Basin Firewheel Acquisition was accounted for as a business combination using the acquisition method.

The Company completed its assessment of the fair values of the assets acquired and liabilities assumed. Accordingly, the following table presents the purchase price allocation of the Delaware Basin Firewheel Acquisition at the indicated date below, based on the fair values of assets acquired and liabilities assumed (in thousands):

	December 31, 2016
Proved oil and gas properties	$ 40,900

Unproved oil and gas properties	112,800
Asset retirement obligations assumed	(500)
Total purchase price	$ 153,200

Divestiture of Southeast New Mexico Properties in the Permian Basin

In February 2017 the Company closed on the sale of its Denton and South Knowles properties in the Northwest Shelf project area in Lea County, New Mexico, for approximately $14.5 million in cash, subject to customary purchase price adjustments. The effective date of this sale was October 1, 2016. The proceeds of the sale were used to reduce amounts outstanding under the Company's Revolving Credit Facility (as defined in Note 5) and for other corporate purposes. As part of the sale, the Company was also no longer liable for asset retirement obligations of $3.6 million at March 31, 2017.

Divestiture of Midstream Assets in the Delaware Basin

In July 2016 Resolute Southwest 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 an existing minority interest holder 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). As the sale did not significantly alter the relationship between capital costs and proved reserves, no gain or loss was recognized.

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. In March 2017 the Earn-out Agreement was amended by the parties to provide for an increase in earn-out payments for the wells drilled and completed in 2017. Earn-out payments are contingent on future drilling, and therefore will be recognized when earned.

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 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.

In April 2017, Resolute Southwest entered into a Crude Oil Connection and Dedication Agreement with Caprock Permian Crude LLC ("Caprock Crude"), an affiliate of Caprock. The agreement provides that Caprock Crude will construct the gathering systems, pipelines and other infrastructure for the gathering of crude oil from our Mustang and Appaloosa operating areas in exchange for customary fees based on the volume of crude oil produced and delivered. Resolute Southwest has agreed to dedicate and deliver all crude oil produced from its acreage in Mustang and Appaloosa to Caprock Crude for gathering for a term through July 31, 2031, coterminous with our other commercial agreements with Caprock. For the first five years of the agreement, the crude oil will be delivered to Midland Station under a joint tariff arrangement between Caprock Crude and Plains Pipeline, L.P. In April 2017, Resolute Southwest also entered into a Crude Oil Purchase Contract with Plains Marketing, L.P. ("Plains") providing for the sale to Plains of substantially all of the crude oil produced from the Mustang and Appaloosa areas for a price equal to an indexed market price less a $1.75 transportation differential that will cover the joint tariff payable to Caprock Crude under the Crude Oil Connection and Dedication Agreement.

Pro Forma Financial Information

The unaudited pro forma financial information for the three and nine months ended September 30, 2016 reflects Resolute's results as if the Delaware Basin Firewheel Acquisition and the sale of the midstream assets in the Delaware Basin had occurred on January 1, 2016 (in thousands, except per share amounts):

	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2016
Revenue	$ 49,805	$ 108,527
Loss from operations	(10,252)	(92,036)
Net loss	(19,634)	(143,564)
Net loss per share		
Basic and diluted	$ (1.14)	$ (8.33)
Weighted average common shares outstanding		
Basic and diluted	17,288	17,237

Note 4 — Earnings per Share

The Company computes basic net income (loss) per share using the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) per share is computed using the weighted average number of shares of common stock and, if dilutive, potential shares of common stock outstanding during the period. Net income (loss) available to common stockholders is computed by deducting both the dividends declared in the period on preferred stock and the dividends accumulated for the period on cumulative preferred stock from net income (loss). Potentially dilutive shares consist of the incremental shares and options issuable under the Company's 2009 Performance Incentive Plan (the "Incentive Plan") as well as common shares issuable upon the assumed conversion of the Convertible Preferred Stock (as defined in Note 7). The treasury stock method is used to measure the dilutive impact of potentially dilutive shares.

The following table details the potential weighted average dilutive and anti-dilutive securities for the periods presented (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Potential dilutive restricted stock	3,762	1,474	3,724	1,015
Anti-dilutive securities	3,762	1,474	3,724	1,386

The following table sets forth the computation of basic and diluted net income (loss) per share of common stock for the periods presented (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net loss available to common shareholders	$(14,602)	$(18,856)	$(3,836)	$(141,074)
Accumulated undeclared dividend	(1,058)	—	(1,058)	—
Adjusted net loss available to common shareholders	$(15,660)	$(18,856)	$(4,894)	$(141,074)
Basic weighted average common shares outstanding	21,941	15,173	21,866	15,122
Add: dilutive effect of non-vested restricted stock	—	—	—	—
Add: dilutive effect of options	—	—	—	—
Diluted weighted average common shares outstanding	21,941	15,173	21,866	15,122
Basic and diluted net loss per common share	$(0.71)	$(1.24)	$(0.22)	$(9.33)

Note 5 — Long Term Debt

As of the dates indicated, the Company's long-term debt consisted of the following (in thousands):

	Principal	Unamortized premium/ (discount)	Unamortized deferred financing costs	September 30, 2017
Revolving credit facility	$125,000	$ —	$ (2,815)	$122,185
8.50% senior notes	525,000	2,438	(4,430)	523,008
Total long-term debt	$650,000	$ 2,438	$ (7,245)	$645,193

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	Principal	Unamortized premium/ (discount)	Unamortized deferred financing costs	December 31, 2016
Revolving credit facility	$10,000	$ —	$ (1,179)	$ 8,821
Secured term loan facility	128,303	(4,882)	(1,282)	122,139
8.50% senior notes	400,000	985	(3,831)	397,154
Total long-term debt	$538,303	$ (3,897)	$ (6,292)	$ 528,114
Current portion of secured term loan facility	128,303	(4,882)	(1,282)	122,139
Long-term debt	$410,000	$ 985	$ (5,010)	$ 405,975

For the three months ended September 30, 2017 and 2016, the Company reported interest expense on long-term debt of $8.5 million and $13.3 million, respectively. For the nine months ended September 30, 2017 and 2016, the Company reported interest expense on long-term debt of $35.0 million and $39.3 million, respectively. Approximately $9.7 million in interest expense was incurred in 2017 as a result of the extinguishment of the Secured Term Loan Facility (as defined below) on January 3, 2017. Additionally, $1.0 million in interest expense was incurred in 2017 as a result of the fees associated with the $100 million unsecured bridge facility with BMO Capital Markets that terminated because the facility was never drawn in connection with the Delaware Basin Bronco Acquisition. The Company capitalized $4.7 million and $0.3 million of interest expense during the three months ended September 30, 2017 and 2016, respectively. The Company capitalized $10.9 million and $1.4 million of interest expense during the nine months ended September 30, 2017 and 2016, respectively. During the three months ended September 30, 2017 and 2016, the Company paid cash for interest expense in the amount of $1.8 million and $3.7 million, respectively. During the nine months ended September 30, 2017 and 2016, the Company paid cash for interest expense in the amount of $24.2 million and $28.2 million, respectively.

Revolving Credit Facility

On February 17, 2017, the Company entered into the Third Amended and Restated Credit Agreement with a syndicate of banks 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"). In connection with entering into the Revolving Credit Facility, the Company repaid all amounts outstanding under the Second Amended and Restated Credit Agreement, dated as of April 15, 2015, by and among Resolute Energy Corporation, as borrower, certain subsidiaries of Resolute Energy Corporation, as Guarantors (defined below), Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, as amended, and terminated that agreement.

The Revolving Credit Facility specifies a maximum borrowing base as determined by the lenders. The determination of the borrowing base takes into consideration the estimated value of Resolute's oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. The borrowing base is redetermined semi-annually, and the amount available for borrowing could be increased or decreased as a result of such redeterminations. Under certain circumstances, either Resolute 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 also includes customary additional terms and covenants that place limitations on certain types of activities, hedging, the payment of dividends, and that require satisfaction of certain financial tests.

On May 8, 2017, the Company entered into the First Amendment to the Third Amended and Restated Credit Agreement. The First Amendment, among other things, amended the leverage ratio covenant to increase the maximum ratio to 4.25:1.00 for the fiscal quarter ending September 30, 2017 and 4.00:1.00 for the fiscal quarters ending thereafter. Furthermore, the amendment provided that the borrowing base shall automatically be reduced by 25% of all unsecured indebtedness of the Company in excess of $500 million. As a result of the issuance of the Incremental Senior Notes (defined below) on May 9, 2017, the borrowing base was reduced to $218.8 million.

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On October 18, 2017, the Company entered into the Second Amendment to the Third Amended and Restated Credit Agreement. The Second Amendment, among other things, amended the definition of EBITDA to include customary transaction costs and expenses incurred in connection with any material acquisition or disposition, provided for certain amendments to the calculation of EBITDA for purposes of the Revolving Credit Facility and amended the covenant governing the ratio of current assets to current liabilities for the quarter ended September 30, 2017 to 0.85 to 1.00 (returning to 1.00 to 1.00 for fiscal quarters ending thereafter). Additionally, the amended covenants prohibit us from entering into derivative arrangements during which such derivative arrangements are in effect for more than (i) for the first year, the greater of 85% of anticipated projected production from proved properties or 75% of our anticipated projected production from properties, (ii) for the second year, 85% of anticipated projected production from proved properties and (iii) for the period after such two year period, the greater of 75% of our anticipated projected production from proved properties or 85% of our anticipated projected production from proved developed producing properties after such two year period (not to exceed a term of 60 months for any such derivative arrangement). Furthermore, the Second Amendment reaffirmed the borrowing base at $218.8 million. Upon the consummation of the disposition of the Aneth Field Properties, the borrowing base was automatically reduced to $210 million. Lastly, the amendment provided that the borrowing base shall automatically be reduced by 25% of all unsecured indebtedness of the Company in excess of $550 million, increased from $500 million. Resolute was in compliance with the terms and covenants of the Revolving Credit Facility at September 30, 2017.

As of September 30, 2017, outstanding borrowings under the Revolving Credit Facility were $125 million with a weighted average interest rate of 4.74%, under a borrowing base of $218.8 million. The borrowing base availability was reduced by $2.8 million in conjunction with letters of credit issued at September 30, 2017.

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, Resolute would be required to eliminate that excess within 120 days following that determination. The Revolving Credit Facility is guaranteed by all of Resolute’s subsidiaries and is collateralized by substantially all of the assets of the Company and it’s wholly-owned subsidiaries.

Each base rate 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 Alternative Base Rate defined as the greater of (i) the Administrative Agent’s Prime Rate (ii) the Federal Funds effective Rate plus 0.5% or (iii) an adjusted London Interbank Offered Rate plus a margin that ranges from 2.0% to 3.0%. Each such margin is based on the level of utilization under the borrowing base.

Secured Term Loan Agreement

In December 2014 Resolute and certain of its subsidiaries, as guarantors, entered into a second lien Secured Term Loan Agreement with Bank of Montreal, as administrative agent, and the lenders party thereto, pursuant to which the Company borrowed $150 million (the “Secured Term Loan Facility”). In May 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 (the “Amendment”) with Bank of Montreal, as administrative agent, and the lenders party thereto, pursuant to which the Company borrowed an additional $50 million of second lien term debt (the “Incremental Term Loans”) under its Secured Term Loan Facility.

In December 2015 the Company retired $70 million of the amount outstanding under the Secured Term Loan Facility following the sale of certain properties in the Midland Basin in accordance with mandatory prepayment provisions stipulated in the Secured Term Loan Facility.

On January 3, 2017, the Company repaid approximately $132 million constituting all amounts due under the Secured Term Loan Facility (including prepayment fees of $3.5 million), with a portion of the proceeds from its previously announced common stock offering that closed on December 23, 2016. In addition $6.2 million of deferred financing costs and original issue discount were expensed as part of the extinguishment. The Secured Term Loan Facility was terminated in connection with the repayment.

Senior Notes

In 2012 the Company consummated two private placements of senior notes with principal totaling $400 million (the “Original Senior Notes”). The Original Senior Notes are due May 1, 2020, and bear an annual interest rate of 8.50% with the interest on the Original Senior Notes payable semiannually in cash on May 1 and November 1 of each year.

On May 9, 2017, the Company consummated a private placement of senior notes totaling an additional $125 million aggregate principal amount of the Company’s 8.50% Senior Notes due 2020 (the “Incremental Senior Notes”), under the same indenture as the Original Senior Notes that were previously issued (collectively referred to as the “Senior Notes”). The net proceeds of the offering of the Incremental Senior Notes, after reflecting the purchasers’ discounts and commissions, and estimated offering expenses, were approximately $125.1 million. The closing of the Incremental Senior Notes occurred on May 12, 2017.

The Senior Notes were issued under an Indenture (the "Indenture") among the Company and all of the Company's subsidiaries, each of which is 100% owned by the Company (the "Guarantors") in a private transaction not subject to the registration requirements of the Securities Act of 1933. In March 2013 and July 2017 the Company registered the exchange of the Original Senior Notes and the Incremental Senior Notes, respectively, with the Securities and Exchange Commission pursuant to registration statements on Form S-4 that enabled holders of the Senior Notes to exchange the privately placed Senior Notes for registered Senior Notes with substantially identical terms. All of the Original Senior Notes and Incremental Senior Notes have been exchanged for publically registered Senior Notes. The Indenture contains affirmative and negative covenants that, among other things, limit the Company's 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 the assets of the Company, engage in transactions with the Company's 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. The Company was in compliance with all financial covenants under its Senior Notes as of September 30, 2017.

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 the Company on not less than 30 or more than 60 days' prior notice, at a redemption price of 102.125%, reducing to 100.000% at May 1, 2018. If a change of control occurs, each holder of the Senior Notes will have the right to require that the Company 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.

The fair value of the Senior Notes at September 30, 2017, was estimated to be $534.3 million based upon data from independent market makers (Level 2 fair value measurement).

Note 6 — Income Taxes

Income tax benefit (expense) during interim periods is based on applying an estimated annual effective income tax rate to year-to-date income (loss), plus any significant, unusual or infrequently occurring items that are recorded in the interim period. The provision for income taxes for the three and nine months ended September 30, 2017 and 2016, differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 35% to income before income taxes. This difference relates primarily to the valuation allowance established, in addition to state income taxes and estimated permanent differences.

The following table summarizes the components of the provision for income taxes:

	Three Months Ended	Nine Months Ended

	September 30, 2017	2016	September 30, 2017	2016
Current income tax benefit	$ 28	$ —	$ 28	$ —
Deferred income tax benefit (expense)	—	—	—	—
Total income tax benefit	$ 28	$ —	$ 28	$ —

The Company had an income tax benefit of less than $0.1 million for the three and nine months ended September 30, 2017. This benefit was the result of a refund of Texas state taxes which were accrued for at year-end 2016 and paid in early 2017. The Company had no reserve for uncertain tax positions as of September 30, 2017. The Company assesses the recoverability of its deferred tax assets each period by considering whether it is more likely than not that all or a portion of the deferred tax assets will be realized. The Company considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. As a result of the Company's analysis, it was concluded that as of September 30, 2017, a valuation allowance should be established against the Company's net deferred tax asset. The Company recorded a valuation allowance as of September 30, 2017 and December 31, 2016, of $312.1 million and $309.6 million, respectively, on its long-term deferred tax asset. The Company will continue to monitor facts and circumstances in the reassessment of the likelihood that the deferred tax assets will be realized.

Note 7 — Stockholders' Equity and Long-term Employee Incentive Plan

Preferred Stock

The Company is authorized to issue up to 1,000,000 shares of preferred stock, par value $0.0001 with such designations, voting and other rights and preferences as may be determined from time to time by the Board of Directors. At September 30, 2017 and December 31, 2016, the Company had 62,500 shares of preferred stock issued and outstanding.

In October 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"). The 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 September 30, 2017, the Company had accumulated undeclared preferred dividends of $1.1 million. A preferred dividend of $1.3 million was declared on October 3, 2017, and paid on October 16, 2017, to holders of record at the close of business on October 1, 2017.

Common Stock

The authorized common stock of the Company consists of 45,000,000 shares. The holders of the common shares are entitled to one vote for each share of common stock. In addition, the holders of the common stock are entitled to receive dividends when, as and if declared by the Board of Directors. At September 30, 2017 and December 31, 2016, the Company had 22,494,040 and 21,932,842 shares of common stock issued and outstanding, respectively.

In May 2016, Resolute adopted a stockholder rights plan and in connection with such plan 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. 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 issued after May 27, 2016, until the earlier of the distribution date 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.

The stockholder rights plan was approved by the Company's stockholders at the 2017 annual meeting in May 2017.

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. All historical share amounts disclosed have been retroactively adjusted to reflect this Reverse Stock Split.

During the fourth quarter of 2016, the Company issued 4,370,000 shares of common stock in a public offering at $38.00 per share for net proceeds of $160.9 million, after deducting fees and estimated expenses. The net proceeds were used to repay outstanding borrowings under the Secured Term Loan Facility and Revolving Credit Facility.

Long Term Employee Incentive Plan

The Company accounts for share-based compensation in accordance with FASB ASC Topic 718, Stock Compensation.

In July 2009, the Company adopted the 2009 Performance Incentive Plan, providing for long-term share-based awards intended as a means for the Company to attract, motivate, retain and reward directors, officers, employees and other eligible persons through the grant of awards and incentives for high levels of individual performance and improved financial performance of the Company. The share-based awards are also intended to further align the interests of award recipients and the Company's stockholders. The maximum number of shares of common stock that may be issued under the Incentive Plan is 4,901,548 (which includes the 1,000,000 shares under Amendment No. 3 to the Incentive Plan approved by the Company's stockholders in May 2016 and the 1,450,000 shares under Amendment No. 4 to the Incentive Plan approved by the Company's stockholders in May 2017).

For the three and nine months ended September 30, 2017 and 2016, the Company recorded expense related to the Incentive Plan as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Time-based restricted stock awards	$1,447	$938	$4,498	$3,658
TSR awards	1,402	221	3,704	777
Stock option awards	253	250	750	686
Total share-based compensation expense	3,102	1,409	8,952	5,121
Time-based restricted cash awards	787	860	2,022	2,549
Performance-based restricted cash awards	465	7,798	1,670	7,925
Cash-settled stock appreciation awards	3,744	7,385	5,648	7,801
Total cash-based compensation expense	4,996	16,043	9,340	18,275
Total Incentive Plan compensation expense	$8,098	$17,452	$18,292	$23,396

As of September 30, 2017, the Company holds unrecognized share-based compensation expense (in thousands) which is expected to be recognized over a weighted-average period as follows:

	Unrecognized Compensation Expense	Weighted Average Years Remaining
Time-based restricted stock awards	$ 12,132	2.3
TSR awards	6,514	2.4
Stock option awards	974	1.3
Total unrecognized compensation expense	$ 19,620	

Equity Awards

Equity awards consist of service-based and performance-based restricted stock and stock options under the Incentive Plan. All historical exercise, base and threshold prices disclosed have been retroactively adjusted to reflect the Reverse Stock Split.

Time-Based Restricted Stock Awards

Shares of time-based restricted stock issued to employees generally vest in three equal annual installments at specified dates based on continued employment. Shares issued to non-employee directors vest in one year based on continued service. The compensation expense to be recognized for the time-based restricted stock awards was measured based on the Company’s closing stock price on the dates of grant, utilizing estimated forfeiture rates between 0% and 15% which are updated periodically based on actual employee turnover. During the nine months ended September 30, 2017, the Company granted 386,977 shares of time-based restricted stock to employees and non-employee directors, pursuant to the Incentive Plan.

The following table summarizes the changes in non-vested time-based restricted stock awards for the nine months ended September 30, 2017:

	Shares	Weighted Average Grant Date Fair Value
Non-vested, beginning of period	151,781	$ 25.07
Granted	386,977	43.44
Vested	(126,875)	27.23
Forfeited	(3,092)	43.96
Non-vested, end of period	408,791	$ 41.64

TSR Awards

In February 2017 the Board and its Compensation Committee awarded performance-based restricted shares to senior employees and executive officers of the Company under the Incentive Plan. The restricted stock grants vest only upon achievement of thresholds of cumulative total shareholder return (“TSR”) as compared to a specified peer group (the “Performance-Vested Shares”). A TSR percentile (the “TSR Percentile”) is calculated based on the change in the value of the Company’s common stock between the grant date and the applicable vesting date, including any dividends paid during the period, as compared to the respective TSRs of a specified group of twelve peer companies. The Performance-Vested Shares vest in three installments to the extent that the applicable TSR Percentile ranking thresholds are met upon the one-, two- and three-year anniversaries of the grant date. Performance-Vested Shares that are eligible to vest on a vesting date, but do not qualify for vesting, become eligible for vesting again on the next vesting date. All Performance-Vested Shares that do not vest as of the final vesting date will be forfeited on such date.

The Board and its Compensation Committee also granted rights to earn additional shares of common stock upon achievement of a higher TSR Percentile (“Outperformance Shares”). The Outperformance Shares are earned in increasing increments based on a TSR Percentile attained over a specified threshold. Outperformance Shares may be earned on any vesting date to the extent that the applicable TSR Percentile ranking thresholds are met in three installments on the one-, two- and three-year anniversaries of the grant date. Outperformance Shares that are earned at a vesting date will be issued to the recipient; however, prior to such issuance, the recipient is not entitled to stockholder rights with respect to Outperformance Shares. Outperformance Shares that are eligible to be earned but remain unearned on a vesting date become eligible to be earned again on the next vesting date. The right to earn any unearned Outperformance Shares terminates immediately following the final vesting date. The Performance-Vested Shares and the Outperformance Shares are referred to as the "TSR Awards."

The compensation expense to be recognized for the TSR Awards was measured based on the estimated fair value at the date of grant using a Monte Carlo simulation model and utilizes estimated forfeiture rates between 0% and 2% which are updated periodically based on actual employee turnover.

The valuation model for TSR Awards used the following assumptions:

Grant Year	Average Expected Volatility	Expected Dividend Yield	Risk-Free Interest Rate
2017	49.07% - 108.21%	0%	0.83% - 1.45%

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The following table summarizes the changes in non-vested TSR Awards for the nine months ended September 30, 2017:

	Shares	Weighted Average Grant Date Fair Value
Non-vested, beginning of period	97,561	$ 66.60
Granted	131,379	77.23
Vested	(97,561)	66.60
Forfeited	(481)	77.21
Non-vested, end of period	130,898	$ 77.23

In addition to the vested TSR awards above, 63,024 outperformance shares were also earned and vested during the nine months ended September 30, 2017, related to the TSR awards granted in 2014.

Stock Option Awards

Options issued to employees to purchase shares of common stock vest in three equal annual installments at specified dates based on continued employment with a ten year term. The compensation expense to be recognized for the option awards was measured based on the Company’s estimated fair value at the date of grant using a Black-Scholes pricing model as well as estimated forfeiture rates between 0% and 15%, no dividends, expected stock price volatility ranging from 63% to 67% and a risk-free rate ranging between 1.75% and 2.27%.

The following table summarizes the option award activity for the nine months ended September 30, 2017:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding, beginning of period	1,052,513	$ 4.03		
Exercised	(75,138)	4.18		
Forfeited	(12,026)	3.52		
Outstanding, end of period	965,349	$ 4.03	8.1	$ 24,775
Exercisable, end of period	385,889	$ 4.71	8.0	$ 9,638

The weighted average grant date fair value of options granted during the nine months ended September 30, 2016, was $1.93. No options were granted during the nine months ended September 30, 2017. The total intrinsic value for options exercised during the nine months ended September 30, 2017 and 2016 was $2.5 million and $0.1 million, respectively.

Liability Awards

Liability awards consist of awards that are settled in cash instead of shares, as discussed below. The fair value of those instruments at a single point in time is not a forecast of what the estimated fair value of those instruments may be in the future. As the fair value of liability awards is required to be re-measured at each period end, amounts recognized in future periods will vary.

Cash-settled Stock Appreciation Rights

A stock appreciation right is the right to receive an amount in cash equal to the excess, if any, of the fair market value of a share of common stock on the date on which the right is exercised over its base price. The February 2016 grants of cash-settled stock appreciation rights hold base prices of $2.65 per share (as to 486,373 rights) and $2.915 per share (as to 1,216,479 rights). The awards granted to employees vest in three equal annual installments and have a ten-year term. The awards granted to non-employee directors vest in one year based on continued service and also have a ten-year term. The compensation expense to be recognized for the cash-settled stock appreciation rights was measured using a Black-Scholes pricing model, estimated forfeiture rates between 0% and 15% which will be updated periodically based on actual employee turnover, no dividends and expected price volatility and risk-free rates relative to the expected term. The fair value of the cash-settled stock appreciation rights as of September 30, 2017, was $45.6 million, of which $23.8 million has been expensed.

Time-Based Restricted Cash Awards

Awards of time-based restricted cash issued to employees vest in three equal annual increments at specified dates based on continued employment. Time-based restricted cash issued to non-employee directors vests in one year based on continued service. The compensation expense to be recognized for the time-based restricted cash awards was measured based on the cash value per unit ($1 per unit) on the date of grant and utilized estimated forfeiture rates between 0% and 25% which will be updated periodically based on actual employee turnover. The total estimated future liability of the time-based restricted cash awards as of September 30, 2017, was $9.5 million, of which $6.4 million has been expensed.

Performance-Based Restricted Cash Awards

The performance criteria for the performance-based restricted cash awards granted in May 2015 are based on future prices of the Company's common stock trading at or above specified thresholds. If and as certain stock price thresholds are met, using a 60 trading day average, various multiples of the performance-vested cash award will be attained. The first stock price hurdle was at $10.00 at which the award was payable at 1x, and the highest stock price hurdle was $40.00 at which the award was payable at a multiple of 6x. Interim hurdles and multiples between these end points are set forth in the governing agreements. As of September 30, 2017, all of the stock price hurdles up to $40.00 had previously been met. A time vesting element will apply to the performance-vested cash awards such that attained multiples will not be paid out earlier than upon satisfaction of a three-year vesting timetable from the date of grant. In order for an award to be paid, both the performance criteria and the time criteria would need to be satisfied. Once a time vesting date passes, the employee is entitled to be paid one third, two thirds or 100%, as applicable, of whatever multiples have been achieved provided the employee continues to be employed by the Company.

The estimated fair value of the performance-based restricted cash awards as of September 30, 2017, was $16.8 million of which $15.7 million has been expensed, based upon the three-year vesting. The fair value was estimated using Black-Scholes option pricing model for a cash or nothing call, an estimated forfeiture rate of 5%, an average effective term of less than one year, no dividends and expected price volatility and risk-free rates relative to the expected term.

Note 8 — Asset Retirement Obligation

Resolute's estimated asset retirement obligation liability is based on estimated economic lives, estimates as to the cost to abandon the wells and facilities 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, that ranges between 7% and 12%. 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. Asset retirement obligations are valued utilizing Level 3 fair value measurement inputs.

The following table provides a reconciliation of Resolute's asset retirement obligations for the periods presented (in thousands):

	Nine Months Ended September 30,	
	2017	2016
Asset retirement obligations at beginning of period	$20,352	$19,238
Additional liability incurred / acquired	246	22

Accretion expense	1,208	1,338
Liabilities settled / sold	(4,062)	(7)
Revisions to previous estimates	702	(20)
Asset retirement obligations at end of period	18,446	20,571
Less: current asset retirement obligations	(1,216)	(1,051)
Long-term asset retirement obligations	$17,230	$19,520

Note 9 — Derivative Instruments

Resolute enters into commodity derivative contracts to manage its exposure to oil and gas price volatility. Resolute has not elected to designate derivative instruments as hedges under the provisions of FASB ASC Topic 815, Derivatives and Hedging. As a result, these derivative instruments are marked to market at the end of each reporting period and changes in the fair value are recorded in the accompanying condensed consolidated statements of operations. Gains and losses on commodity derivative instruments from Resolute's price risk management activities are recognized in other income (expense). The cash flows from derivatives are reported as cash flows from operating activities unless the derivative contract is deemed to contain a financing element. Derivatives deemed to contain a financing element are reported as financing activities in the condensed consolidated statement of cash flows.

The Company utilizes fixed price swaps, basis swaps, option contracts and two- and three-way collars. These instruments generally entitle Resolute (the floating price payer in most cases) to receive settlement from the counterparty (the fixed price payer in most cases) for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable to each calculation period is less than the fixed strike price or floor price. The Company would pay the counterparty if the settlement price for the scheduled trading days applicable to each calculation period exceeds the fixed strike price or ceiling price. The amount payable by Resolute, if the floating price is above the fixed or ceiling price is the product of the notional contract quantity and the excess of the floating price over the fixed or ceiling price per calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional contract quantity and the excess of the fixed or floor price over the floating price per calculation period. A three-way collar consists of a two-way collar contract combined with a put option contract sold by the Company with a strike price below the floor price of the two-way collar. The Company receives price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, the Company receives the cash market price plus the variance between the two put option strike prices. This type of instrument captures more value in a rising commodity price environment, but limits the benefits in a downward commodity price environment. Basis swaps, when used in connection with fixed price swaps, are used to fix the price differential between the NYMEX commodity price and the index price at which the production is sold.

As of September 30, 2017, the fair value of the Company's commodity derivatives was a net liability of $11.1 million (Level 2 fair value measurement).

The following table represents Resolute's commodity swap contracts as of September 30, 2017:

	Oil (NYMEX WTI)		Gas (NYMEX Henry Hub)		NGL (Mont Belvieu)	
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	MMBtu per Day	Weighted Average Swap Price per MMBtu	Bbl per Day	Weighted Average Swap Price per Bbl
Oct – Dec 2017[1]	3,000	$ 53.93	14,000	$ 3.476	300	$ 19.53
Jan – Dec 2018[2]	3,248	$ 50.63	—	$ —	—	$ —
Jan – Dec 2018[3]	4,210	$ 47.73	—	$ —	—	$ —
Jan – Dec 2019[3]	4,000	$ 50.20	—	$ —	—	$ —
Jan – Dec 2020[3]	3,788	$ 50.20	—	$ —	—	$ —

[1] Subsequent to September 30, 2017, Resolute terminated all 2017 NGL swap contract volumes.

[2] Subsequent to September 30, 2017, Resolute terminated 2018 oil swap contract volumes totaling 500 Bbl per day at a weighted average price of $51.50 per Bbl.

[3] As of September 30, 2017, Resolute was party to certain commodity swap contracts averaging 4,000 Bbl per day for the years 2018-2020. These contracts were entered into pursuant to the terms of the Purchase and Sale Agreement related to the Aneth Disposition (as defined below) discussed at Note 11. These contract amounts were novated to the buyer upon the closing of the transaction.

The following table represents Resolute's two-way commodity collar contracts as of September 30, 2017:

	Oil (NYMEX WTI)			Gas (NYMEX Henry Hub)		
Remaining Term	Bbl per Day	Weighted Average Floor	Weighted Average Ceiling	MMBtu per Day	Weighted Average Floor	Weighted Average Ceiling

		Price per Bbl	Price per Bbl		Price per MMBtu	Price per MMBtu
Oct – Dec 2017[1]	2,500	$ 47.80	$ 60.19	9,250	$ 2.477	$ 3.301

[1] Subsequent to September 30, 2017, Resolute terminated 2017 two-way gas collar contract volumes totaling 6,000 MMBtu per day at a weighted average floor price of $2.600 per MMBtu and a weighted average ceiling price of $3.600 per MMBtu.

The following table represents Resolute's three-way oil collar contracts as of September 30, 2017:

	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
Oct – Dec 2017[1]	1,500	$ 40.00	$ 50.00	$ 60.10
Jan – Dec 2018	2,748	$ 40.18	$ 49.27	$ 53.86

[1] Subsequent to September 30, 2017, Resolute terminated all 2017 three-way oil collar contract volumes.

The following table represents Resolute's three-way gas collar contracts as of September 30, 2017:

	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
Oct – Dec 2017	1,500	$ 2.750	$ 3.250	$ 4.010

The following table represents Resolute's commodity option contracts as of September 30, 2017:

	Oil (NYMEX WTI)	
Remaining Term	Bbl per Day	Weighted Average Sold Call Price per Bbl
Jan – Dec 2018	1,100	$ 55.00
Jan – Dec 2019	1,100	$ 62.85

Subsequent to September 30, 2017, Resolute entered into additional oil swap contracts as summarized below:

	Oil (NYMEX WTI)	
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl
Jan – Jun 2018	1,000	$ 54.00
Jul – Dec 2018	500	$ 51.95

Subsequent to September 30, 2017, Resolute entered into an additional three-way oil collar contract as summarized below:

	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
Jul – Dec 2018	1,000	$ 40.00	$ 50.00	$ 56.00

The table below summarizes the location and amount of commodity derivative instrument gains and losses reported in the condensed consolidated statements of operations (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Other income (expense):				
Commodity derivative settlement gain	$2,354	$21,357	$3,760	$69,649
Mark-to-market gain (loss)	(16,073)	(17,385)	819	(81,388)
Commodity derivative instruments gain (loss)	$(13,719)	$3,972	$4,579	$(11,739)

Credit Risk in Derivative Instruments

Resolute is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above. All counterparties have high credit ratings and are current or former lenders under Resolute’s Revolving Credit Facility. Accordingly, Resolute is not required to provide any credit support to its counterparties other than cross collateralization with the properties securing the Revolving Credit Facility. Resolute’s derivative contracts are documented with industry standard contracts known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. Master Agreement (“ISDA”). Typical terms for each ISDA include credit support requirements, cross default provisions, termination events, and set-off provisions. Resolute generally has set-off provisions with its lenders that, in the event of counterparty default, allow Resolute to set-off amounts owed under the Revolving Credit Facility or other general obligations against amounts owed for derivative contract liabilities.

Resolute does not offset the fair value amounts of commodity derivative assets and liabilities with the same counterparty for financial reporting purposes. The following is a listing of Resolute’s commodity derivative assets and liabilities required to be measured at fair value on a recurring basis and where they are classified within the hierarchy as of September 30, 2017, and December 31, 2016 (in thousands):

	Level 2	
	September 30, 2017	December 31, 2016
Assets		
Derivative instruments, current	$1,653	$ 218
Derivative instruments, long term	—	—
Total assets	$1,653	$ 218
Liabilities		
Derivative instruments, current	$8,177	$ 8,014
Derivative instruments, long term	4,557	4,104
Total liabilities	$12,734	$ 12,118

As of September 30, 2017, the maximum amount of loss in the event of all counterparties defaulting was $0.8 million.

Note 10 — Commitments and Contingencies

CO_2 Take-or-Pay Agreements

As of September 30, 2017, Resolute was party to a take-or-pay purchase agreement with Kinder Morgan CO_2 Company L.P., under which Resolute was committed to buy specified volumes of CO_2. This agreement was assigned to and assumed by the buyer in connection with the closing of the Aneth Disposition (defined below). See Note 11 for additional information related to the Aneth Disposition. The purchased CO_2 was for use in Resolute's enhanced tertiary recovery projects in Aneth Field. Resolute was obligated to purchase a minimum daily volume of CO_2 or pay for any deficiencies at the price in effect when delivery was to have occurred. The ultimate CO_2 volumes planned for use on the enhanced recovery projects exceed the minimum daily volumes provided in these take-or-pay purchase agreements.

Future minimum CO_2 purchase commitments as of September 30, 2017, under this purchase agreement which transferred to the Aneth Field buyer upon closing of the transaction, based on prices and volumes in effect at September 30, 2017, were as follows (in thousands):

Year	CO_2 Purchase Commitments
2017	1,380
2018	5,475
Total	$ 6,855

The terms of the CO_2 contract, as amended in Amendment No. 3 to the Kinder Morgan Product Sale and Purchase Contract dated July 1, 2007, contains a unit price floor, below which the price cannot fall. As a result, the Company was exposed to the risk of paying higher than the market rate for CO_2 in a climate of declining oil and CO_2 prices. Based on this floor pricing term, the Company determined that this contract contained an embedded derivative. However, assuming the prices in effect as of September 30, 2017, the fair value of this embedded derivative was immaterial.

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Note 11 — Subsequent Events

Aneth Field Disposition

On September 14, 2017, Resolute and certain of its wholly-owned subsidiaries (together, the “Sellers”) entered into a Membership Interest and Asset Purchase Agreement (the “Purchase and Sale Agreement”) pursuant to which the Sellers agreed to sell their respective equity interests in Resolute Aneth, LLC, the entity which holds all of Resolute’s interest in Aneth Field, and certain other assets associated with Aneth Field operations, to an affiliate of Elk Petroleum Limited (“Elk”) (the “Buyer”). The sale closed on November 6, 2017 for total consideration of up to $195 million (the “Aneth Disposition”). The effective date of this sale is October 1, 2017. The proceeds of the Aneth Disposition initially will be used to repay borrowings under Resolute’s Revolving Credit Facility. The Company is in the process of assessing whether a gain will be recognized on the Aneth Disposition.

Under the terms of the Purchase and Sale Agreement, the Buyer funded a performance deposit of $10 million which was creditable against the purchase price. This performance deposit is contained in other long term liabilities on the Condensed Consolidated Balance Sheet at September 30, 2017. In addition to the performance deposit, Resolute received cash consideration of $150 million at closing, subject to customary purchase price adjustments, and is entitled to receive additional cash consideration of up to $35 million if oil prices exceed certain levels in the three years after closing, as follows: Buyer will pay Resolute $40,000 for each week day in the twelve months after closing that the WTI spot oil price exceeds $52.50 per barrel (up to $10 million); $50,000 for each week day in the twelve months following the first anniversary of closing that the oil price exceeds $55.00 per barrel (up to $10 million) and $60,000 for each week day in the twelve months following the second anniversary of closing that the oil price exceeds $60.00 per barrel (up to $15 million).

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report on Form 10-K for the year ended December 31, 2016, as well as the accompanying financial statements and the related notes contained elsewhere in this report. References to "Resolute," "the Company," "we," "our," and "us" refer to Resolute Energy Corporation and its subsidiaries.

Overview

We are a publicly traded, independent oil and gas company with assets located primarily in the Delaware Basin in west Texas. As discussed in Note 11 to the Condensed Consolidated Financial Statements, we closed on the disposition of our Aneth Field Properties on November 6, 2017. The historical results of operations of the Aneth Field are contained in our financial position and results as of September 30, 2017 and for the three and nine months ended September 30, 2017. Our development activity is focused on our 27,100 gross (21,100 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 and to focus on 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.

Pursuant to full cost accounting rules, we perform ceiling tests each quarter on our proved oil and gas assets. We recorded a non-cash impairment of the carrying value of our proved oil and gas properties of $58 million during the nine months ended September 30, 2016, as a result of the ceiling test limitation. No impairment was recorded during the nine months ended September 30, 2017. If in future periods a negative factor impacts 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, we may incur further full cost ceiling impairment related to our oil and gas properties in such periods.

For 2017 the Board initially approved a capital expenditure plan of $210 to $240 million primarily focused on a two rig drilling program spudding 22 gross wells in the Delaware Basin. This original capital program did not contemplate the Delaware Basin Bronco Acquisition or any related capital activities. When we included approximately $37 million in net capital allocated to the development of the Bronco Assets, approximately $15 million in increased capital associated with the acquisition of incremental working interests in certain second quarter wells and unbudgeted outside-operated wells, we previously increased our 2017 capital guidance range to $270 million to $285 million. Due to the continuing efficiency of our drilling to date we have now completed the 22 wells originally contemplated in our 2017 plan. With the closing of the Aneth Disposition our Board has approved an expansion to our 2017 capital program, which will allow us to retain the rigs and completion crews that have provided these excellent results. Under the extended plan we will spud an incremental five wells and complete one incremental well beyond our original program. This should result in our carrying eight drilled but uncompleted wells into the first quarter of 2018. We expect these wells will be completed in early 2018 providing significant momentum to our first quarter production growth. The total capital required to execute the extended capital plan will be approximately $19 million. In addition to executing the extended plan, we are currently completing the planning process necessary to potentially add a third rig in early 2018. The total capital required to execute the expanded capital plan will be approximately $19 million, causing us to increase our 2017 capital guidance range to $290 million to $305 million.

We expect our 2017 capital 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 and C. We anticipate that substantially all of our acreage will be held by production by the end of 2017.

During the second and third quarters of 2017, we experienced a limited number of instances of well interference, primarily in Appaloosa, as we completed infill wells in close proximity to older producing wells in the same horizon. We estimate these events reduced production for each quarter marginally. These types of events are not atypical for development in the Permian Basin and have been reported by other operators as well. We have made operational adjustments with the objective of reducing these impacts in the future. First, we anticipate that our future drilling will be done in groups of two to four wells followed by sequential frac operations on all of the wells in the group. We believe this shift to pad drilling will ultimately result in savings of between $0.5 and $1.0 million dollars per pad. Second, we have moved to increase the density of perforation clusters in our frac design. We do not expect this to change our overall proppant loading or completion costs. The goal of this revised design is to give us a more effective completion in the near wellbore environment while reducing the instances where individual fractures reach out long distances and negatively affect adjacent wells. The shift to pad drilling is expected to modestly impact production growth in the fourth quarter as a small number of completions are delayed.

We expect that the effect of the mid-period sale of our Aneth Field Properties will reduce fourth quarter production by 4,000 Boe per day. This is partially offset by contribution from the Delaware Basin Bronco Acquisition as well as capital activity across our Reeves County asset base. Combining these factors, fourth quarter production is anticipated to be between 26,000 and 27,000 Boe per day. Full year production is expected to be between 24,500 to 25,500 Boe per day including the full year impact of the Aneth Disposition and the contribution of approximately 1,000 Boe per day from the Delaware Basin Bronco Acquisition.

During the third quarter, we experienced a modest shift in our oil percentage resulting from our mix of producing wells. Of the seven wells turned to production, four of them were in our Bronco and Mustang areas where we have higher initial gas to oil ratios. Based on our mix of producing wells and the sale of Aneth Field, which is 99% oil, we expect that our 2017 oil percentage will be between 60 and 62 percent.

We will 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 reduce 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 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 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 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. 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 Secured Term Loan Facility (including prepayment fees). The Secured Term Loan Facility was terminated in connection with the repayment.

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 in cash, subject to customary purchase price adjustments. The effective date of this sale was October 1, 2016. The proceeds of the sale were used for general corporate purposes. As part of the sale, the Company was also no longer liable for asset retirement obligations of $3.6 million at March 31, 2017.

On April 27, 2017, Resolute Southwest entered into a Crude Oil Connection and Dedication Agreement with Caprock Crude, an affiliate of Caprock. The agreement provides that Caprock Crude will construct the gathering systems, pipelines and other infrastructure for the gathering of crude oil from our Mustang and Appaloosa operating areas in exchange for customary fees based on the volume of crude oil produced and delivered. Resolute Southwest has agreed to dedicate and deliver all crude oil produced from its acreage in Mustang and Appaloosa to Caprock Crude for gathering for a term through July 31, 2031, coterminous with our other commercial agreements with Caprock. For the first five years of the agreement, the crude oil will be delivered to Midland Station under a joint tariff arrangement between Caprock Crude and Plains Pipeline, L.P. On April 27, 2017, Resolute Southwest also entered into a Crude Oil Purchase Contract with Plains Marketing, L.P. providing for the sale to Plains of substantially all of the crude oil produced from the Mustang and Appaloosa areas for a price equal to an indexed market price less a $1.75 transportation differential that will cover the joint tariff payable to Caprock Crude under the Crude Oil Connection and Dedication Agreement.

On March 3, 2017, Resolute Southwest entered into a Purchase and Sale Agreement with CP Exploration II, LLC and Petrocap CPX, LLC pursuant to which Resolute Southwest agreed to acquire certain producing and undeveloped oil and gas properties in the Delaware Basin in Reeves County, Texas. The closing of the Delaware Basin Bronco Acquisition occurred on May 15, 2017, with an effective date of May 1, 2017. The acquisition was accounted for as an asset acquisition. The Company acquired these properties for $161.3 million, which it financed substantially with proceeds received from the offering of $125 million of 8.50% Senior Notes due 2020 that closed in May 2017. The properties acquired included approximately 4,600 net acres in Reeves County, Texas, which were considered predominantly unproved, 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.

While the closing of the Incremental Senior Notes issuance related to the Delaware Basin Bronco Acquisition resulted in a short term rise in our level of indebtedness on an absolute basis and in relation to our cash flows, the sale of Aneth Field, which closed in the fourth quarter of 2017, was a significant deleveraging event. We secured a precautionary amendment to ensure that we remained in compliance with our covenants under our Revolving Credit Facility during this interim period of increased indebtedness.

On September 14, 2017, to complete our repositioning as a pure-play Delaware Basin company, Resolute entered into the Purchase and Sale Agreement pursuant to which we agreed to sell the equity interests in Resolute Aneth, LLC, the entity which holds all of Resolute's interest in Aneth Field, and certain other assets associated with Aneth Field operations, to Elk. The sale closed on November 6, 2017 for total consideration of up to $195 million, comprised of $160 million ($150 million of which was received at closing and $10 million of which was a deposit received in the third quarter), adjusted for normal closing purchase price adjustments and up to an additional $35 million if oil prices exceed certain levels in the next three years. The effective date of the sale is October 1, 2017. The proceeds of the Aneth Disposition initially will be used to repay borrowings under Resolute's Revolving Credit Facility.

Our Revolving Credit Facility and Senior Notes include customary terms and covenants that place limitations on certain types of activities and require satisfaction of certain financial tests. We were in compliance with all material terms and covenants of the Revolving Credit Facility and Senior Notes at September 30, 2017.

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 from 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, 2016 and 2017. 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. Since then we have added reserves by drilling vertical and horizontal wells in our various operating areas. We will seek to add reserves through similar means in the future. 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 had 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. 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.

Credit facility EBITDA. Credit facility EBITDA (a non-GAAP measure) is defined under the Revolving Credit Facility 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, cash-settled incentive award payments and noncontrolling interest amounts. Credit facility 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. 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, non-recurring cash-settled incentive award payments and noncontrolling interest amounts. Adjusted EBITDA is used as a supplemental liquidity or performance measure by our management and by external users of our financial statements such as investors, 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.

Credit facility EBITDA and Adjusted EBITDA should not be considered as alternatives to, or more meaningful than net income available to common shareholders, 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 credit facility EBITDA and Adjusted EBITDA, when evaluating our financial performance and liquidity. Credit facility EBITDA and Adjusted EBITDA exclude 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 credit facility EBITDA and Adjusted EBITDA may not be comparable to credit facility EBITDA and Adjusted EBITDA of any other company because other entities may not calculate credit facility EBITDA and Adjusted EBITDA in the same manner.

Permian Basin Properties

Our Permian Basin Properties, constituting 59% of net proved reserves as of December 31, 2016, are located in the Permian Basin of west Texas. Our project area located in the Delaware Basin portion of the Permian Basin, in Reeves County, targets the Wolfcamp formation.

During the nine months ended September 30, 2017, we completed 25 gross (19.9 net) wells and had 6 gross (5.0 net) wells awaiting completion at quarter end. Furthermore, as of September 30, 2017, we were in the process of drilling 2 gross (2.0 net) wells. All such wells are located in the Delaware Basin.

See Note 3 to the Condensed Consolidated Financial Statements for additional information on the following events:

- In May 2017 we acquired certain Reeves County interests in the Delaware Basin.
- In February 2017 we sold our Denton and South Knowles properties in the Northwest Shelf project area in the Permian Basin.
- In October 2016 we acquired certain Reeves County interests in the Delaware Basin.
- In August 2016 we sold certain midstream asset interests in the Delaware Basin.

Aneth Field Properties

The Aneth Field Properties constituted 41% of our net proved reserves as of December 31, 2016. The working interests we held at September 30, 2017 in Aneth Field, a mature, long-lived oil producing field, were located primarily on the Navajo Reservation in southeast Utah. We owned a majority of the working interests in, and were the operator of, three federal production units which constituted the Aneth Field Properties. These were the Aneth Unit, the McElmo Creek Unit and the Ratherford Unit, in which we owned working interests of 62.4%, 67.5% and 58.6%, respectively, at September 30, 2017.

In November 2017 we completed the sale of our Aneth Field Properties. See Note 11 to the Condensed Consolidated Financial Statements for additional information.

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 and competition from other sources of energy. Historical oil prices have been volatile and are expected to fluctuate widely in the future. Sustained periods of low prices for oil could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas that we can economically produce, and our ability to obtain capital.

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

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 three and nine months ended September 30, 2017, in comparison to results for the three and nine months ended September 30, 2016.

The following table presents our sales volumes, revenues and operating expenses, and sets forth our sales prices, costs and expenses on a barrel of oil equivalent ("Boe") basis for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Sales:				
Oil (MBbl)	1,554	1,072	4,168	2,582
Gas (MMcf)	3,563	1,436	8,366	2,908
NGL (MBbl)	480	169	1,056	313
Total sales (MBoe)	2,628	1,480	6,618	3,380
Average daily sales (Boe/d)	28,566	16,085	24,240	12,336
Average Sales Prices:				
Oil ($/Bbl)	$43.53	$39.55	$44.64	$36.27
Gas ($/Mcf)	2.47	2.49	2.51	1.98
NGL ($/Bbl)	10.59	8.61	10.23	7.59
Average sales price ($/Boe, excluding commodity derivative settlements)	$31.03	$32.04	$32.91	$30.12
Operating Expenses ($/Boe):				
Lease operating	$9.55	$11.20	$9.57	$13.63
Production and ad valorem taxes	3.34	3.27	3.28	3.62
General and administrative	3.63	4.84	4.45	7.00
General and administrative (excluding non-cash compensation expense)	2.45	3.94	3.11	5.56
Cash-settled incentive awards	1.90	10.84	1.36	5.41
Depletion, depreciation, amortization and accretion	9.71	8.43	9.65	9.97

Quarter Ended September 30, 2017, Compared to the Quarter Ended September 30, 2016

Revenue. Revenue from oil and gas activities increased by 72% to $81.6 million during 2017, from $47.4 million during 2016. Of the $34.2 million increase in revenue, approximately $36.8 million was attributable to increased production, offset by $2.6 million attributable to decreased commodity pricing ($31.03 per Boe in 2017 versus $32.04 per Boe in 2016). Sales volumes increased 78% to 2,628 MBoe during 2017 as compared to 1,480 MBoe during 2016, principally as a result of production from newly drilled and completed wells 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 increased 51% to $25.1 million during 2017, from $16.6 million during 2016. On a per-unit basis, lease operating expense decreased 15% to $9.55 per Boe in 2017 compared to $11.20 per Boe in 2016. The decrease in per-unit operating expense is primarily due to the increase in production from mid-length and long lateral horizontal wells in the Delaware Basin, which increased by a greater percentage than the associated lease operating expense.

Production and ad valorem taxes increased to $8.8 million during 2017, as compared to $4.8 million during 2016, but remained relatively unchanged on a per-unit basis as compared to 2016. Production and ad valorem taxes were 10.8% of total revenue in 2017 versus 10.2% of total revenue in 2016. The higher production and ad valorem taxes as a percentage of revenue in 2017 as compared to 2016 is primarily the result of higher ad valorem tax estimates in 2017. As production increased period over period, production taxes increased in a corresponding manner.

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 $9.5 million during 2017, as compared to $7.2 million during 2016. The $2.3 million, or 33% increase, primarily resulted from increases in share based compensation due to a shift in 2017 from granting cash-based to equity-based long-term incentive awards. On a per-unit basis, general and administrative expenses decreased to $3.63 per Boe in 2017 from the $4.84 per Boe in 2016. Cash-based general and administrative expense was $6.4 million, or $2.45 per Boe, in 2017 compared to $5.8 million, or $3.94 per Boe, in 2016.

Cash-settled incentive award expense is comprised of the expense related to the grant of time-and performance-based restricted cash awards as well as cash-settled stock appreciation rights under the long-term incentive program. 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.

Cash-settled incentive award expense decreased to $5.0 million in 2017, as compared to $16.0 million in 2016. This decrease was the result of the achievement of multiple performance targets (which primarily occurred in 2016) that are based on the Company’s stock price under the performance-based restricted cash awards as well as a decrease in expense related to the fair value of the cash-settled stock appreciation rights under the long-term incentive program. Actual cash payments during the 2017 period were $0.6 million.

Depletion, depreciation, amortization and accretion expenses increased to $25.5 million during 2017, as compared to $12.5 million during 2016 primarily as a result of the 78% increase in production. On a per-unit basis, depreciation, amortization and accretion expenses increased to $9.71 per Boe in 2017 compared to $8.43 per Boe in 2016. The increase on a per-unit basis was attributable to capitalized costs increasing by a greater percentage than the associated proved reserve quantities between the two periods.

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 and associated production, 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. No impairment was recorded during the three months ended September 30, 2017 and 2016. If in future periods a negative factor impacts 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 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 2017 the loss on oil and gas commodity derivatives was $13.7 million, consisting of $16.1 million mark-to-market losses offset by $2.4 million of derivative settlement gains. During 2016 the gain on oil and gas commodity derivatives was $4.0 million, consisting of $21.4 million of derivative settlement gains offset by $17.4

million of mark-to-market losses.

Interest expense in 2017 decreased to $8.5 million from the $13.3 million recorded in 2016. The decrease in interest expense was primarily due to the termination of the Secured Term Loan Facility and increases in amounts capitalized offset by interest incurred on the May 2017 issuance of the 8.50% Incremental Senior Notes. The components of our interest expense are as follows (in thousands):

	Three Months Ended September 30,	
	2017	2016
8.50% senior notes	$11,156	$8,500
Secured term loan facility	—	3,607
Revolving credit facility	1,554	177
Amortization of deferred financing costs, senior notes premium and secured term loan facility discount	538	1,312
Bridge facility commitment fee and other, net	(33)	25
Capitalized interest	(4,688)	(349)
Total interest expense	$8,527	$13,272

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Income Tax Benefit (Expense). Income tax benefit recognized during the three months ended September 30, 2017 was less than $0.1 million, which was the result of a refund of Texas state taxes which were accrued for at year-end 2016 and paid in early 2017. No income tax benefit or expense was recognized during the three months ended September 30, 2016 due to the deferred tax asset valuation allowance previously established by the Company.

Nine Months Ended September 30, 2017, Compared to the Nine Months Ended September 30, 2016

Revenue. Revenue from oil and gas activities increased by 114% to $217.8 million during 2017, from $101.8 million during 2016. Of the $116.0 million increase in revenue, approximately $97.5 million was attributable to increased production and $18.5 million was attributable to increased commodity pricing ($32.91 per Boe in 2017 versus $30.12 per Boe in 2016). Sales volumes increased 96% to 6,618 MBoe during 2017 as compared to 3,380 MBoe during 2016, principally as a result of production from newly drilled and completed wells in the Delaware Basin.

Operating Expenses. Lease operating expenses increased to $63.3 million during 2017, from $46.1 million during 2016. On a per-unit basis, lease operating expense decreased 30% to $9.57 in 2017 compared to $13.63 in 2016. The significant decrease in per-unit operating expense is primarily due to the significant increase in production from mid-length and long lateral horizontal wells in the Delaware Basin, which increased by a greater percentage than the associated lease operating expense.

Production and ad valorem taxes increased to $21.7 million during 2017, as compared to $12.2 million during 2016 and were less on a per-unit basis, compared to 2016. Production and ad valorem taxes were 10.0% of total revenue in 2017 versus 12.0% of total revenue in 2016. The lower production and ad valorem taxes as a percentage of revenue in 2017 as compared to 2016 are attributable to the increase in the percentage of revenue realized in the State of Texas, which has a lower effective tax rate than the Aneth Field properties. This decrease is also the result of the timing of the assessment of ad valorem taxes, as they are assessed on January 1^{st} of each year, based on the producing wells at that point in time and are not updated for wells that come online throughout the year.

General and administrative expenses increased to $29.4 million during 2017, as compared to $23.7 million during 2016. The $5.7 million, or 24%, increase primarily resulted from an increase in share-based compensation expense due to a shift in 2017 from granting cash-based to equity-based long-term incentive awards and a restoration of short-term incentive compensation which had been reduced during 2016 in response to lower commodity prices, offset by an increase in the portion of general and administrative expenses capitalized. On a unit-of-production basis, general and administrative expenses decreased 36%. Cash-based general and administrative expense was $20.6 million, or $3.11 per Boe, in 2017 compared to $18.8 million, or $5.56 per Boe, in 2016.

Cash-settled incentive award expense decreased to $9.0 million in 2017, as compared to $18.3 million in 2016. This decrease was primarily the result of the achievement of multiple performance targets (which primarily occurred in 2016) that are based on the Company's stock price under the performance-based restricted cash awards as well as a decrease in expense related to the fair value of cash-settled stock appreciation rights under the long-term incentive program. Actual cash payments during the 2017 period were $11.9 million.

Depletion, depreciation, amortization and accretion expenses increased to $63.9 million during 2017, as compared to $33.7 million during 2016, principally as a result of the 96% increase in production. Conversely, on a per-unit basis, depletion, depreciation, amortization and accretion expenses remained relatively unchanged at $9.65 per Boe in 2017 compared to $9.97 per Boe in 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 non-cash impairment of the carrying value of our proved oil and gas properties of $58 million during the nine months ended September 30, 2016, as a result of the ceiling test limitation. No impairment was recorded during the nine months ended September 30, 2017. If in future periods a negative factor impacts 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 2017 the gain on oil and gas commodity derivatives was $4.6 million, consisting of $3.8 million of derivative settlement gains and $0.8 million of mark-to-market gains. During 2016 the loss on oil and gas commodity derivatives was $11.7 million, consisting of $81.4 million of mark-to-market losses offset by $69.7 million of derivative settlement gains.

Interest expense in 2017 decreased to $35.0 million from the $39.3 million recorded in 2016. The decrease in interest expense was primarily due to the extinguishment of the Secured Term Loan Facility as well as increases in the amount capitalized offset by the penalties incurred related to the repayment of the Secured Term Loan Facility and the issuance of the 8.50% Incremental Senior Notes. The components of our interest expense are as follows (in thousands):

	Nine Months Ended September 30,	
	2017	2016
8.50% senior notes	$29,602	$25,500
Secured term loan facility	3,631	10,742
Revolving credit facility	2,857	559
Amortization of deferred financing costs, senior notes premium and secured term loan facility discount	8,801	3,922
Bridge facility commitment fee and other, net	971	33
Capitalized interest	(10,859)	(1,426)
Total interest expense	$35,003	$39,330

Approximately $9.7 million in interest expense was incurred in 2017 as a result of the extinguishment of the Secured Term Loan Facility on January 3, 2017. Additionally, $1.0 million in interest expense was incurred in 2017 as a result of the fees associated with the $100 million unsecured bridge facility with BMO Capital Markets that terminated because the facility was never drawn in connection with the Delaware Basin Bronco Acquisition.

Income Tax Benefit (Expense). Income tax benefit recognized during the nine months ended September 30, 2017 was less than $0.1 million, which was the result of a refund of Texas state taxes which were accrued for at year-end 2016 and paid in early 2017. No income tax benefit or expense was recognized during the nine months ended September 30, 2016 due to the deferred tax asset valuation allowance previously established by the Company.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash generated from operations, amounts available under our Revolving Credit Facility, proceeds from the issuance of debt and equity securities and sales of oil and gas properties. For purposes of Management's Discussion and Analysis of Liquidity and Capital Resources, we have analyzed our cash flows and capital resources for the nine months ended September 30, 2017 and 2016.

Nine Months Ended

	September 30,	
	2017	2016
	(in thousands)	
Cash provided by operating activities	$111,950	$58,695
Cash used in investing activities	(345,341)	(67,059)
Cash provided by (used in) financing activities	101,190	(25)

Net cash provided by operating activities was $112.0 million in 2017 as compared to $58.7 million for the 2016 period. The increase in net cash provided by operating activities in 2017 as compared to 2016 was primarily due to increased revenue resulting from the 96% increase in 2017 production volumes.

Net cash used in investing activities was $345.3 million in 2017 compared to $67.1 million in 2016. The primary investing activities in 2017 were cash used for capital expenditures of $219.0 million and acquisitions of $161.3 million. Capital expenditures in 2017 consisted primarily of $209.5 million in drilling activities and infrastructure projects in the Permian Basin, $6.5 million in facility projects in Aneth Field and $3.0 million in CO_2 acquisition for Aneth Field. Capital divestitures in 2017 included $13.2 million of cash receipts related to the Earnout Agreement entered into in connection with the divestiture of the midstream assets in the Delaware Basin and $13.1 million of net proceeds primarily from the sale of the New Mexico Properties. The primary investing activity in 2016 was cash used for capital expenditures of $98.3 million. Capital expenditures in 2016 consisted primarily of $87.1 million in drilling activities and infrastructure projects in the Permian Basin, $6.3 million in facility projects in Aneth Field and $4.9 million in CO_2 acquisition for Aneth Field. Capital divestitures in 2016 included $33.0 million of proceeds from the sale of the Reeves County midstream assets.

Net cash provided by financing activities was $101.2 million in 2017 compared to less than $0.1 million used in 2016. The primary financing activities in 2017 were $126.9 million of proceeds received from the issuance of the Incremental Senior Notes and $115.0 million in net borrowings under the Revolving Credit Facility, offset by the repayment of $128.3 million of principal on the Secured Term Loan.

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. 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.

While the closing of the Incremental Senior Notes issuance related to the Delaware Basin Bronco Acquisition resulted in a short term rise in our level of indebtedness on an absolute basis and in relation to our cash flows, the sale of Aneth Field, which closed in the fourth quarter of 2017, was a significant deleveraging event. We secured a precautionary amendment to ensure that we remained in compliance with our covenants under our Revolving Credit Facility during this interim period of increased indebtedness. As discussed above, in future periods we may again use additional borrowings under our Revolving Credit Facility or issue other debt or equity securities to fund ongoing operations or asset acquisitions.

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

On February 17, 2017, we entered into the Third Amended and Restated Credit Agreement with a syndicate of banks 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. In connection with entering into the Revolving Credit Facility, we repaid all amounts outstanding under the Second Amended and Restated Credit Agreement, dated as of April 15, 2015, by and among Resolute Energy Corporation, as Borrower, certain subsidiaries of Resolute Energy Corporation, as Guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, as amended, and terminated that agreement.

The Revolving Credit Facility specifies a maximum borrowing base as determined by the lenders in their sole discretion. 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 also includes customary additional terms and covenants that place limitations on certain types of activities, hedging, the payment of dividends, and that require satisfaction of certain financial tests.

On May 8, 2017, we entered into the First Amendment to the Third Amended and Restated Credit Agreement. The First Amendment, among other things, amended the leverage ratio covenant to increase the maximum ratio to 4.25:1.00 for the fiscal quarter ending September 30, 2017 and 4.00:1.00 for fiscal quarters ending thereafter. Furthermore, the amendment provided that the borrowing base shall automatically be reduced by 25% of all unsecured indebtedness of the Company in excess of $500 million. As a result of the Incremental Senior Notes on May 9, 2017 the borrowing base was reduced to $218.8 million.

On October 18, 2017, we entered into the Second Amendment to the Third Amended and Restated Credit Agreement. The Second Amendment, among other things, amended the definition of EBITDA to include customary transaction costs and expenses incurred in connection with any material acquisition or disposition, provided for certain amendments to the calculation of EBITDA for purposes of the Revolving Credit Facility (providing for annualization of quarterly EBITDA through the first quarter of 2018) and amended the covenant governing the ratio of current assets to current liabilities for the quarter ended September 30, 2017 to 0.85 to 1.00 (returning to 1.00 to 1.00 for fiscal quarters ending thereafter). Additionally, the amended covenants prohibit us from entering into derivative arrangements during which such derivative arrangements are in effect for more than (i) for the first year, the greater of 85% of anticipated projected production from proved properties or 75% of our anticipated projected production from properties, (ii) for the second year, 85% of anticipated projected production from proved properties and (iii) for the period after such two year period, the greater of 75% of our anticipated projected production from proved properties or 85% of our anticipated projected production from proved developed producing properties after such two year period (not to exceed a term of 60 months for any such derivative arrangement). Furthermore, the Second Amendment reaffirmed our borrowing base at $218.8 million. Upon the consummation of the disposition of the Aneth Field Properties, our borrowing base was automatically decreased to $210 million. Lastly, the amendment provided that the borrowing base shall automatically be reduced by 25% of all unsecured indebtedness of the Company in excess of $550 million, increased from $500 million. We were in compliance with all material terms and covenants of the Revolving Credit Facility at September 30, 2017.

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 assets of the Company's and its wholly-owned subsidiaries.

Each borrowing under the Revolving Credit Facility accrues interest at either (a) the London Interbank Offered Rate, plus a margin that ranges from 3.0% to 4.0% or (b) the Alternative Base Rate defined as the greater of (i) the Administrative Agent's Prime Rate (ii) the Federal Funds Effective Rate plus 0.5% or (iii) an adjusted 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.

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

In December 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. In May 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 we borrowed an additional $50 million of Incremental Term Loans under its Secured Term Loan Facility.

In December 2015 we retired $70 million of the amount outstanding under the Secured Term Loan Facility following the sale of certain properties in the Midland Basin in accordance with mandatory prepayment provisions stipulated in the Secured Term Loan Facility.

On January 3, 2017, we paid approximately $132 million constituting all amounts due under the Secured Term Loan Facility (including prepayment fees of $3.5 million), with a portion of the proceeds from the previously announced common stock offering that closed on December 23, 2016. In addition, $6.2 million of deferred financing costs and original issue discount were expensed as part of the extinguishment. 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 Original 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.

On May 9, 2017, we consummated a private placement of senior notes totaling $125 million aggregate principal amount of the Company's 8.50% Incremental Senior Notes due 2020. The Incremental Senior Notes constituted an additional issuance of notes under the same indenture as the Original Senior Notes that were previously issued. The net proceeds of the offering of the Senior Notes, after reflecting the purchasers' discounts and commissions, and estimated offering expenses, were approximately $125.1 million. The closing of the Incremental Senior Notes occurred on May 12, 2017.

The Senior Notes were issued under an Indenture among the Company and all of the Company's subsidiaries, each of which is 100% owned by the Company, in a private transaction not subject to the registration requirements of the Securities Act of 1933. In March 2013 and July 2017 we registered the exchange of the Original Senior Notes and the Incremental Senior Notes, respectively, with the Securities and Exchange Commission pursuant to registration statements on Form S-4 that enabled holders of the Senior Notes to exchange the privately placed Senior Notes for 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 September 30, 2017.

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 a redemption price of 102.125%, reducing to 100.000% at May 1, 2018. 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. In light of the significantly lower interest rate environment currently compared to when the Senior Notes were first issued, the Company is evaluating a potential refinance of the Senior Notes.

Preferred Stock

In October 2016, the Company entered into a Purchase Agreement with BMO Capital Markets Corp., pursuant to which the Company agreed to issue and sell to Initial Purchaser 55,000 shares of the Company's 8 % Series B Cumulative Perpetual Convertible Preferred Stock, par value $0.0001 per share and, at Initial Purchaser's option, up to 7,500 additional shares of Convertible Preferred Stock. The 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 September 30, 2017, the Company has accumulated undeclared preferred dividends of $1.1 million. A preferred dividend of $1.3 million was declared on October 3, 2017 and paid on October 16, 2017, to holders of record at the close of business on October 1, 2017.

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.

Critical Accounting Policies

The following discussion should be read in conjunction with the “Critical Accounting Policies” disclosure contained in our Annual Report on Form 10-K for the year ended December 31, 2016.

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). The unique inputs of each of the equity awards are outlined as follows:

- Stock option award expense – measured using a Black-Scholes pricing model, no dividends, and expected price volatility and risk-free rates relative to the expected term.
- Time-based restricted stock award expense – measured based on the Company’s closing stock price on the date of grant.
- TSR award expense – measured based a Monte Carlo simulation model, no dividends, and expected price volatility and risk-free rates relative to the expected term.

Cash-settled incentive award expense is measured quarterly and is amortized over the requisite service period (usually the vesting period). The unique inputs of each of the liability awards are outlined as follows:

- Cash-settled stock appreciation rights – measured using a Black Scholes pricing model, no dividends, and expected price volatility and risk-free rates relative to the expected term.
- Time-based restricted cash awards – measured based on the cash value per unit ($1 per unit) on the date of grant.
- Performance-based restricted cash awards – measured using a Black-Scholes cash-or-nothing valuation model, no dividends, and expected price volatility and risk-free rates relative to the expected term.

The Company estimates forfeitures in calculating the cost related to share-based compensation expense and cash-settled incentive awards expense as opposed to recognizing these forfeitures and the corresponding reduction in expense as they occur.

The Company calculates the respective award’s price volatility using an average of the Company’s peer group (as determined by our Total Stockholder Return awards) based on the date of grant or quarterly valuation date for the expected term. Risk-free rates are obtained directly from the U.S Department of the Treasury.

ITEM 3. QUANTITATIVE 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 Facility, the form of derivative instruments to be entered into is at our discretion, but prohibit us from entering into derivative arrangements during which such derivative arrangements are in effect for more than (i) for the first year, the greater of 85% of anticipated projected production from proved properties or 75% of our anticipated projected production from properties, (ii) for the second year, 85% of anticipated projected production from proved properties and (iii) for the period after such two year period, the greater of 75% of our anticipated projected production from proved properties or 85% of our anticipated projected production from proved developed producing properties after such two year period (not to exceed a term of 60 months for any such derivative arrangement).

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. As of September 30, 2017, the fair value of our commodity derivatives was a net liability of $11.1 million.

The following table represents our oil swap contracts as of September 30, 2017:

	Oil (NYMEX WTI)		
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Oct – Dec 2017	3,000	$ 53.93	$ 538
Jan – Dec 2018[1]	3,248	$ 50.63	$ (1,445)
Jan – Dec 2018[2]	4,210	$ 47.73	$ (6,205)
Jan – Dec 2019[2]	4,000	$ 50.20	$ (1,033)
Jan – Dec 2020[2]	3,788	$ 50.20	$ (455)

[1] Subsequent to September 30, 2017, we terminated 2018 oil swap contract volumes totaling 500 Bbl per day at a weighted average price of $51.50 per Bbl.

[2] As of September 30, 2017, we were party to certain commodity swap contracts averaging 4,000 Bbl per day for the years 2018-2020. These contracts were entered into pursuant to the terms of the Purchase and Sale Agreement related to the Aneth Disposition discussed at Note 11. These contracts were novated to the buyer upon the closing of the transaction.

The following table represents our gas swap contracts as of September 30, 2017:

	Gas (NYMEX Henry Hub)		
Remaining Term	MMBtu per Day	Weighted Average Swap Price per MMBtu	Fair Value of Asset (Liability) (in thousands)
Oct – Dec 2017	14,000	$ 3.476	$ 542

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The following table represents our NGL swap contracts as of September 30, 2017:

	NGL (Mont Belvieu)		
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Oct – Dec 2017[1]	300	$ 19.53	$ (239)

[1] Subsequent to September 30, 2017, we terminated all 2017 NGL swap contract volumes.

The following table represents our two-way oil collar contracts as of September 30, 2017:

	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)
Oct – Dec 2017[1]	2,500	$ 47.80	$ 60.19	$ 154

The following table represents our two-way gas collar contracts as of September 30, 2017:

	Gas (NYMEX Henry Hub)			
Remaining Term	MMBtu per Day	Weighted Average Floor Price per MMBtu	Weighted Average Ceiling Price per MMBtu	Fair Value of Asset (Liability) (in thousands)
Oct – Dec 2017[1]	9,250	$ 2.477	$ 3.301	$ (103)

[1] Subsequent to September 30, 2017, we terminated 2017 two-way gas collar contract volumes totaling 6,000 MMBtu per day at a weighted average floor price of $2.600 per MMBtu and a weighted average ceiling price of $3.600 per MMBtu.

The following table represents our three-way oil collar contracts as of September 30, 2017:

	Oil (NYMEX WTI)				
Remaining Term	Bbl per Day	Weighted Average	Weighted Average	Weighted Average	Fair Value of

		Short Put Price per Bbl	Floor Price per Bbl	Ceiling Price per Bbl	Asset (Liability) (in thousands)
Oct – Dec 2017[1]	1,500	40.00	$ 50.00	$ 60.10	$ 113
Jan – Dec 2018	2,748	40.18	$ 49.27	$ 53.86	$ (1,083)

[1] Subsequent to September 30, 2017, we terminated all 2017 three-way oil collar contract volumes.

The following table represents our three-way gas collar contracts as of September 30, 2017:

	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)
Oct – Dec 2017	1,500	$ 2.750	$ 3.250	$ 4.010	$ 32

The following table represents our commodity option contracts as of September 30, 2017:

	Oil (NYMEX WTI)		
Remaining Term	Bbl per Day	Weighted Average Sold Call Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jan – Dec 2018	1,100	$ 55.00	$ (1,208)
Jan – Dec 2019	1,100	$ 62.85	$ (689)

Subsequent to September 30, 2017, we entered into additional oil swap contracts as summarized below:

	Oil (NYMEX WTI)	
Commodity Swaps	BBl per Day	Weighted Average Swap Price per Bbl
Jan – Jun 2018	1,000	$ 54.00
Jul – Dec 2018	500	$ 51.95

Subsequent to September 30, 2017, we entered into an additional three-way oil collar contract as summarized below:

	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
Jul – Dec 2018	1,000	$ 40.00	$ 50.00	$ 56.00

Interest Rate Risk

At September 30, 2017, we had $125 million of outstanding debt under the Revolving Credit Facility. Interest is calculated under the terms of the agreement based principally on a LIBOR spread. A 10% increase in LIBOR would result in an estimated $0.2 million increase in annual interest expense. We do not currently have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

Credit Risk 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 have high credit ratings and 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. 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 4. CONTROLS AND PROCEDURES

Our management, with the participation of Richard F. Betz, our Chief Executive Officer, and Theodore Gazulis, our Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of September 30, 2017. Based on the evaluation, those officers have concluded that:

- our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms; and
- our disclosure controls and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 was accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

There has not been any change in the Company's internal control over financial reporting that occurred during the quarterly period ended September 30, 2017 that has materially affected, or is reasonably likely to affect, the Company's internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Resolute is 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 1A. RISK FACTORS

Information about material risks related to our business, financial condition and results of operations for the quarter ended September 30, 2017 does not materially differ from those set out in Part I, Item 1A of the Annual Report on Form 10-K for the year ended December 31, 2016. The additional risk factor set forth below is related to the Aneth Disposition.

We repositioned Resolute to a pure-play Delaware Basin company by disposing of our Aneth Field Properties, and the divesture could materially adversely affect our business, financial position, results of operations or cash flows.

We disposed of our Aneth Field Properties in order to reposition us as a pure-play Delaware Basin company. The disposition of Aneth Field Properties will provide meaningful additional capital to the Company. This capital will be deployed initially to reduce leverage.

Aneth Field has been a meaningful part of our operations, and sales of oil and gas from Aneth Field represented a meaningful part of our total cash flow. At December 31, 2016, Aneth Field held approximately 41% of our net proved reserves and averaged production of 6,161 Boe per day in 2016 (representing 44% of total Company production), of which approximately 95% was oil. During 2016, Aneth Field had sales of 2,132 MBbl of oil and 739 MMcf of gas with average realized prices of $36.37 per Bbl of oil and $1.31 per Mcf of gas with average production costs of $20.24 per Boe of lease operating expenses and $4.31 per Boe of production and ad valorem taxes. Additionally at December 31, 2016, Aneth Field consisted of 43,218 developed gross acres or 67.1% of our total developed gross acreage and 27,157 developed net acres or 60.5% of our total developed net acreage.

For the nine months ended September 30, 2017, Aneth Field averaged production of 5,938 Boe per day (representing 25% of total Company production). These 2017 sales were comprised of 1,555 MBbl of oil and 393 MMcf of gas with average realized prices of $42.17 per Bbl of oil and $1.57 per Mcf of gas with average production costs of $21.61 per Boe of lease operating expenses and $5.43 per Boe of production and ad valorem taxes.

The price we ultimately receive from the divestiture of the Aneth Field Properties will be contingent on the price of oil (as specified in the additional cash consideration clause outlined in Note 11 to the Condensed Consolidated Financial Statements) and may be affected by the foregoing or other factors. Additionally, there can be no assurances that our subsequent investments in the Delaware Basin from the proceeds and the redeployment of resources made available by the sale of our Aneth Field Properties will meet our internal production and profitability projections for a pure-play Delaware Basin strategy or even meet current production and profitability projections prior to divesting of the Aneth Field Properties. We previously depended in part on the cash flow generated by our Aneth Field Properties for the payment of our indebtedness, and if we do not meet our internal projections and experience lower cash flow due to the sale of our Aneth Field Properties, it may materially adversely affect our ability make payments on our outstanding indebtedness. Consequently, the sale of our Aneth Field Properties could materially adversely affect our business, financial position, results of operations or cash flows.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS
Issuer Purchases of Equity Securities

In connection with the vesting of Company restricted common stock under the 2009 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.

2017	Total Number of Shares Purchased[(1)(2)]	Average Price Paid Per Share
March 1 – 31	84,835	$ 38.22
April 1 – 30	1,088	$ 41.76
May 1 – 31	154	$ 38.09
June 1 – 30	32	$ 40.69
July 1 – 31	166	$ 29.77
August 1 – 31	183	$ 33.60
September 1 – 30	2,947	$ 29.63

1) All shares purchased in 2017 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 September 30, 2017, the maximum number of shares that may yet be purchased would not exceed the employees' portion of taxes withheld on unvested shares (539,689 shares), outstanding stock options (965,349 options), shares yet to be granted under the Incentive Plan (1,907,312 shares) and potential Outperformance Shares (130,898 shares).

ITEM 3. DEFAULTS UPON SENIOR SECURITIES
None.

ITEM 4. MINE SAFETY DISCLOSURES
Not applicable.

ITEM 5. OTHER INFORMATION
None.

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ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	Membership Interest and Asset Purchase Agreement dated September 14, 2017 by and between Resolute Energy Corporation, Hicks Acquisition Company I. Inc., and Resolute Natural Resources Company, LLC as sellers, Resolute Aneth, LLC as the Company and Elk Petroleum Aneth, LLC as Buyer and Elk Petroleum Limited as Parent Guarantor (filed herewith). Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule or exhibit will be furnished supplementally to the to the Securities and Exchange Commission upon request.
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (filed herewith)
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (filed herewith)
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith)
101	The following materials are filed herewith: (i) XBRL Instance Document, (ii) XBRL Taxonomy Extension Schema Document, (iii) XBRL Taxonomy Extension Calculation Linkbase Document, (iv) XBRL Taxonomy Extension Labels Linkbase Document, (v) XBRL Taxonomy Extension Presentation Linkbase Document, and (vi) XBRL Taxonomy Extension Definition Linkbase Document.

SIGNATURES

Pursuant to the requirements of the Exchange Act of 1934, the Registrant caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Signature	Capacity	Date
/s/ Richard F. Betz Richard F. Betz	Chief Executive Officer and Director (Principal Executive Officer)	November 6, 2017
/s/ Theodore Gazulis Theodore Gazulis	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	November 6, 2017