Resolute Energy Corp
Form 10-Q
August 06, 2018
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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 June 30, 2018

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 Incorporation or Organization)	27-0659371 (I.R.S. Employer 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 July 31, 2018, 23,166,491 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 "expect," "estimate," "project," "budget," "forecast," "anticipate," "intend," "plan," "may," "will," "could," "should," "poised," "believes," "predicts," "potent similar expressions are intended to identify such statements; however the absence of these words does not mean the statements are not forward-looking. Forward-looking statements included in this report relate to, among other things, anticipated production in 2018; anticipated capital expenditures and activity in 2018; future leverage ratios; the impact and amount of contingency payments from the parent of the Aneth Field purchaser; potential proceeds from a midstream transaction with the Bronco properties; future earnout payments; future infrastructure and other capital projects; our financial condition and management of the Company in the current commodity price environment, including expectations regarding price and basis differential fluctuations; future financial and operating results; liquidity and availability of capital; future borrowing base adjustments and the effect thereof; future pad drilling timing and 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 2018; the potential impact of well interference and the effectiveness of operational adjustments to mitigate it; the prospectivity of our properties and acreage; and the anticipated accounting treatment of various activities. Although we believe that these statements are based upon reasonable current assumptions, no assurance can be given that the future results covered by the forward-looking statements will be achieved. Forward-looking statements can be subject to risks, uncertainties and other factors that could cause actual results to differ materially from future results expressed or implied by the forward-looking statements. The forward-looking statements in this report are primarily, although not exclusively, located under the heading "Risk Factors." All forward-looking statements speak only as of the date made. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we undertake no obligation to update any forward-looking statement. Factors that could cause actual results to differ materially from our expectations include, among others, those factors referenced in the "Risk Factors" section of this report, if any, in our Annual Report on Form 10-K for the year ended December 31, 2017, as amended ("Form 10-K"), and such things as:

- the Company's ability to successfully implement its strategy to create long-term stockholder value;
- 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;
- increases in the differentials between index oil on gas prices and the prices we receive;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil, NGL and gas and other processing and transportation considerations;
- 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 potential for downspacing, infill or multi-lateral drilling in the Permian Basin or obstacles thereto;
- the completion and success of exploratory drilling on our properties;
- the timing and amount of future production of oil and gas;
- changes in our production mix 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;
- potential operational disruption caused by the actions of stockholder activists;
- 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, hedging 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;
- our ability to achieve the growth and benefits we expect from our acquisitions;
- 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 and resources;
- 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;
- potential 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 "early time" rates, 24-hour peak IP rates, 30-day peak IP rates, 60-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 and represent three stream gross production. 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 6,000 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 Form 10-Q and in our Form 10-K, 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)

	June 30, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$815	$3,762
Accounts receivable	61,395	63,420
Commodity derivative instruments	12,030	526
Contingent payment derivative instrument	3,204	8,311
Prepaid expenses and other current assets	2,713	1,856
Total current assets	80,157	77,875
Property and equipment, at cost:		
Oil and gas properties, full cost method of accounting		
Unproved	272,600	248,059
Proved	2,227,757	2,030,316
Other property and equipment	13,367	12,879
Accumulated depletion, depreciation and amortization	(1,783,350)	(1,737,116)
Net property and equipment	730,374	554,138
Other assets:		
Contingent payment derivative instrument	15,823	9,635
Other assets	274	274
Total assets	$826,628	$641,922
Liabilities and Stockholders' Deficit		
Current liabilities:		
Accounts payable	$30,165	$16,077
Accrued expenses	100,176	53,754
Accrued revenue payable	28,196	28,255
Accrued cash-settled incentive awards	31,251	34,317
Accrued interest payable	8,680	7,574
Commodity derivative instruments	33,715	20,822
Total current liabilities	232,183	160,799
Long-term liabilities:		
Revolving credit facility	71,090	27,487
Senior notes	597,709	523,240
Commodity derivative instruments	4,503	990
Other long-term liabilities	3,918	3,815
Total liabilities	909,403	716,331
Stockholders' deficit:		
Convertible preferred stock, $0.0001 par value; 1,000,000 shares authorized; issued and outstanding 62,500 shares at June 30, 2018 and December 31, 2017; $62.5 million liquidation preference	—	—
Common stock, $0.0001 par value; 45,000,000 shares authorized; issued and outstanding	2	2

23,181,746 and 22,527,652 shares at June 30, 2018 and December 31, 2017, respectively		
Additional paid-in capital	968,188	957,426
Accumulated deficit	(1,050,965)	(1,031,837)
Total stockholders’ deficit	(82,775)	(74,409)
Total liabilities and stockholders’ deficit	$ 826,628	$ 641,922

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenue:				
Oil	$58,395	$60,703	$118,046	$118,362
Gas	5,670	6,468	12,030	10,819
Natural gas liquids	9,315	3,089	18,022	5,671
Total revenue	73,380	70,260	148,098	134,852
Operating expenses:				
Lease operating	15,366	19,890	27,031	38,246
Production and ad valorem taxes	5,521	5,565	11,061	11,534
Depletion, depreciation and amortization	23,494	22,333	47,031	38,368
General and administrative	15,875	9,472	36,942	19,887
Cash-settled incentive awards	(47)	(1,413)	11,294	4,014
Total operating expenses	60,209	55,847	133,359	112,049
Income from operations	13,171	14,413	14,739	22,803
Other income (expense):				
Interest expense, net	(8,515)	(8,779)	(16,083)	(26,476)
Commodity derivative instruments gain (loss)	(12,120)	7,458	(21,522)	18,298
Contingent payment derivative instrument gain	3,703	—	6,282	—
Other income (expense)	29	136	(5)	76
Total other expense	(16,903)	(1,185)	(31,328)	(8,102)
Net income (loss)	(3,732)	13,228	(16,589)	14,701
Preferred stock dividends	(1,270)	(2,538)	(2,539)	(3,935)
Net income (loss) available to common stockholders	$(5,002)	$10,690	$(19,128)	$10,766
Net income (loss) per common share:				
Basic	$(0.22)	$0.49	$(0.86)	$0.49
Diluted	$(0.22)	$0.47	$(0.86)	$0.47
Weighted average common shares outstanding:				
Basic	22,306	21,917	22,194	21,828
Diluted	22,306	22,894	22,194	22,836

See notes to condensed consolidated financial statements

RESOLUTE ENERGY CORPORATION

Condensed Consolidated Statements of Stockholders' Deficit (Unaudited)

(in thousands)

	Common Shares	Stock Amount	Preferred Stock Shares	Amount	Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Deficit
Balance as of January 1, 2018	22,528	$ 2	63	$ —	$ 957,426	$ (1,031,837)	$ (74,409)
Issuance of stock, restricted stock and stock-based compensation	559	—	—	—	13,339	—	13,339
Redemption of restricted stock for employee income tax and restricted stock forfeitures	(75)	—	—	—	(2,893)	—	(2,893)
Exercise of employee options to purchase common stock	170	—	—	—	316	—	316
Preferred stock dividend	—	—	—	—	—	(2,539)	(2,539)
Net loss	—	—	—	—	—	(16,589)	(16,589)
Balance as of June 30, 2018	23,182	$ 2	63	$ —	$ 968,188	$ (1,050,965)	$ (82,775)

See notes to condensed consolidated financial statements

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RESOLUTE ENERGY CORPORATION

Condensed Consolidated Statements of Cash Flows (Unaudited)

(in thousands)

	Six Months Ended June 30, 2018	2017
Operating activities:		
Net income (loss)	$(16,589)	$14,701
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and amortization	47,031	38,368
Amortization of deferred financing costs and long-term debt premium and discount	1,150	8,263
Stock-based compensation	13,339	5,951
Commodity derivative instruments (gain) loss	21,522	(18,298)
Commodity derivative settlement gain (loss)	(16,620)	1,406
Unrealized contingent payment derivative instrument gain	(6,282)	—
Change in operating assets and liabilities:		
Accounts receivable	7,114	(11,366)
Other current assets	(857)	(113)
Accounts payable and accrued expenses	9,375	11,252
Accrued interest payable	1,106	1,995
Net cash provided by operating activities	60,289	52,159
Investing activities:		
Oil and gas exploration and development expenditures	(180,735)	(118,484)
Proceeds from sale of oil and gas properties	7,738	20,292
Purchase of oil and gas properties	—	(161,264)
Purchase of other property and equipment	(2,045)	(2,396)
Restricted cash	—	(25)
Other long-term assets	—	8
Net cash used in investing activities	(175,042)	(261,869)
Financing activities:		
Proceeds from bank borrowings	237,000	213,000
Repayments of bank borrowings	(194,000)	(123,000)
Proceeds from issuance of senior notes	74,625	126,875
Repayment of term loan	—	(128,303)
Payment of financing costs	(703)	(5,068)
Payment of preferred dividend	(2,539)	(2,666)
Redemption of restricted stock for employee income taxes	(2,893)	(3,295)
Proceeds from exercise of employee options to purchase common stock	316	177
Net cash provided by financing activities	111,806	77,720
Net decrease in cash and cash equivalents	(2,947)	(131,990)
Cash and cash equivalents at beginning of period	3,762	133,089
Cash and cash equivalents at end of period	$815	$1,099

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"). The Company closed on the sale of Aneth Field, located in the Paradox Basin in southeast Utah (the "Aneth Field Properties" or "Aneth Field"), on November 6, 2017. All 2017 periods presented include the results related to Aneth Field, prior to the disposition. 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, 2017. 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.

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, 2017. These unaudited condensed consolidated financial statements are to be read in conjunction with the consolidated financial statements appearing in Resolute's Form 10-K and related notes.

Effective January 1, 2018, Resolute adopted ASC 606, Revenue from Contracts with Customers, utilizing the modified retrospective method. See Note 9 for further details related to the Company's adoption of this standard and revenue recognition accounting policy.

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; the estimated fair value and allocation of the purchase price related to business combinations; stock-based compensation expense; cash-settled long-term incentive expense; depletion, depreciation, and amortization; accrued liabilities; and revenue and related receivables.

Accounts Receivable

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

	June 30, 2018	December 31, 2017
Trade	$12,413	$ 18,079
Revenue	41,799	43,136
Contingent payment derivative	6,760	1,560
Other	423	645
Total accounts receivable	$61,395	$ 63,420

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 between fifteen and thirty days and are collected in less than two months, and the Company has had minimal bad debts.

The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. As of June 30, 2018 and December 31, 2017, the Company had no allowance for doubtful accounts recorded.

Accrued Expenses

The Company’s accrued expenses consist of the following as of the dates indicated (in thousands):

	June 30, 2018	December 31, 2017
Capital expenditures	$61,277	$ 15,503
General and administrative	12,547	14,510
Lease operating	11,887	14,809
Other	14,465	8,932
Total accrued expenses	$100,176	$ 53,754

The majority of the Company’s accrued expenses consist of accrued capital expenditures related to the exploration and development of oil and gas properties.

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 and all related income tax effects.

No impairment was recorded for the three and six months ended June 30, 2018 and 2017. If in future periods a negative factor affects 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.

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 Company adopted this standard in the second quarter of 2017.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). ASC 606 requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The new standard became effective for the Company and was adopted on January 1, 2018. The Company elected the modified retrospective transition method. The adoption of this standard had no impact on the Company's consolidated financial statements. See Note 9 for further details related to the Company's adoption of this standard.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which requires lessees to present nearly all leasing arrangements on the balance sheet as liabilities along with a corresponding right-of-use asset. The ASU will replace most existing lease guidance in GAAP when it becomes effective for the Company on January 1, 2019. Although early application is permitted, the Company does not plan to early adopt the ASU. The Company is evaluating the effect that ASU 2016-02 will have on its consolidated financial statements and related disclosures. We believe that adoption of the standard will result in increases to our assets and liabilities on our consolidated balance sheet. However, we have not yet determined the extent of the adjustments that will be required upon implementation of the standard. We continue to monitor relevant industry guidance regarding the implementation of ASU 2016-02 and will adjust our implementation strategies as necessary.

Note 3 — Acquisitions and Divestitures

Acquisition of Reeves County Properties in the Delaware Basin

In May 2017, Resolute Natural Resources Southwest, LLC ("Resolute Southwest"), a wholly owned subsidiary of the Company, closed on a Purchase and Sale Agreement with CP Exploration II, LLC and Petrocap CPX, LLC pursuant to which Resolute Southwest acquired certain undeveloped and developed oil and gas properties in the Delaware Basin in Reeves County, Texas (the "Delaware Basin Bronco Acquisition").

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 consideration as unproved oil and gas property.

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.

Divestiture of Aneth Field

In November 2017, Resolute and certain of its wholly-owned subsidiaries closed on a Purchase and Sale Agreement pursuant to which the Company sold 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 Petroleum") (the "Aneth Field Sale").

Under the terms of the Purchase and Sale Agreement, the buyer funded a performance deposit of $10 million which was credited against the purchase price. Resolute received additional cash consideration of $150 million at closing, subject to normal purchase price adjustments. Additionally, Resolute 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: Elk Petroleum, an affiliate of 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). As of closing, the fair value of the additional consideration was $16.0 million. 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. Under seller accounting for contingent consideration, the Company has determined that this arrangement meets the definition of a derivative. See Note 8 – Derivative Instruments, for additional information regarding the contingent payment derivative instrument. As the sale did not significantly alter the relationship between capital costs and proved reserves, no gain or loss was recognized.

In conjunction with the Aneth Field Sale, certain management members resigned from their positions effective January 1, 2018. In connection with their resignation, these individuals and the Company entered into separation agreements. The material terms of the separation agreements, including compensation payable thereunder and treatment of long-term incentive awards, are consistent with their respective employment agreements with the Company dated January 1, 2017, and various long-term incentive award agreements. Effective January 1, 2018, all awards held were modified contemporaneously with the termination of their employment.

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 (the "New Mexico Properties"), for approximately $14.5 million in cash, subject to customary purchase price adjustments.

Divestiture of Midstream Assets in the Delaware Basin

In 2016, in connection with the Purchase and Sale Agreement with Caprock Permian Processing LLC and Caprock Field Services LLC, as buyers (collectively, "Caprock") of the Mustang and Appaloosa project areas in Reeve County, Texas ("Mustang" and "Appaloosa," respectively), 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 wells drilled and completed in 2017. Earn-out payments are contingent on future drilling, and therefore will be recognized when earned. As of June 30, 2018, we have earned $36.0 million of earn-out payments, $5.2 million and $7.4 million of this total was earned in the three and six months ended June 30, 2018, respectively.

In connection with the closing of the transactions contemplated by the Purchase and Sale Agreement related to the Mustang and Appaloosa project areas, 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. Pursuant to the agreement, Caprock Crude constructed 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 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 six months ended June 30, 2017 reflects Resolute's results as if the Aneth Field Sale had occurred on January 1, 2017 (in thousands, except per share amounts):

	Three Months Ended June 30, 2017	Six Months Ended June 30, 2017

Revenue	$48,506	$89,737
Income from operations	13,522	18,968
Net income available to common stockholders	10,585	7,890
Net income per share		
Basic	$0.48	$0.36
Diluted	$0.46	$0.35
Weighted average common shares outstanding		
Basic	21,917	21,828
Diluted	22,894	22,836

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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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Potential dilutive securities	4,016	3,782	3,955	3,704
Anti-dilutive securities	4,016	2,116	3,955	2,116

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss) available to common stockholders	$(5,002)	$10,690	$(19,128)	$10,766
Basic weighted average common shares outstanding	22,306	21,917	22,194	21,828
Add: dilutive effect of non-vested restricted stock	—	118	—	138
Add: dilutive effect of options	—	859	—	870
Diluted weighted average common shares outstanding	22,306	22,894	22,194	22,836
Basic net income (loss) per common share	$(0.22)	$0.49	$(0.86)	$0.49
Diluted net income (loss) per common share	(0.22)	0.47	(0.86)	0.47

Note 5 — Long Term Debt

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

	Principal	Unamortized net premium	Unamortized deferred financing costs	June 30, 2018

Revolving credit facility	$73,000	$ —	$ (1,910)	$71,090
8.50% senior notes	600,000	1,439	(3,730)	597,709
Total long-term debt	$673,000	$ 1,439	$ (5,640)	$668,799

	Principal	Unamortized net premium	Unamortized deferred financing costs	December 31, 2017
Revolving credit facility	$30,000	$ —	$ (2,513)	$ 27,487
8.50% senior notes	525,000	2,222	(3,982)	523,240
Total long-term debt	$555,000	$ 2,222	$ (6,495)	$ 550,727

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For the three months ended June 30, 2018 and 2017, the Company incurred net interest expense on long-term debt of $8.5 million and $8.8 million, respectively. For the six months ended June 30, 2018 and 2017, the Company incurred net interest expense on long-term debt of $16.1 million and $26.5 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 (defined below) on January 3, 2017. The Company capitalized $5.6 million and $3.7 million of interest expense during the three months ended June 30, 2018 and 2017, respectively. The Company capitalized $10.8 million and $6.2 million of interest expense during the six months ended June 30, 2018 and 2017, respectively. During the three months ended June 30, 2018 and 2017, the Company paid cash for interest (net of amounts capitalized) in the amount of $18.0 million and $14.7 million, respectively. During the six months ended June 30, 2018 and 2017, the Company paid cash for interest (net of amounts capitalized) in the amount of $13.8 million and $16.2 million, respectively.

Revolving Credit Facility

In February 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, all 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' sole discretion. 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 includes covenants that require, among other things, Resolute to maintain a ratio of current assets to current liabilities of no less than 1.00 to 1.00 and a ratio of funded debt to EBITDA (as defined in the Revolving Credit Facility) of no more than 4.25 to 1.00 as of June 30, 2018, moving to 4.00 to 1.00 as of September 30, 2018 and thereafter. 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.

In March 2018, the Company entered into the Third Amendment to the Third Amended and Restated Credit Agreement. The Third Amendment, among other things, amended the definition of Applicable Margin so that if the ratio of total funded debt to EBITDA for the period ending June 30, 2018, exceeds 4.00:1.00, then each applicable rate per annum shall be increased by 0.25% per annum until the date such ratio is calculated for the quarter ending September 30, 2018. It also amended the definition of EBITDA to include certain costs incurred by the Company in connection with activist investor campaigns and provides for certain amendments to the calculation of EBITDA, and amended the covenant governing the ratio of funded debt to EBITDA. Lastly, the Third Amendment also provided that the borrowing base shall automatically be reduced by 25% of all unsecured indebtedness of the Company in excess of $600 million. In April 2018, the borrowing base was reaffirmed at $210.0 million. Resolute was in compliance with the terms and covenants of the Revolving Credit Facility at June 30, 2018.

As of June 30, 2018, outstanding borrowings under the Revolving Credit Facility were $73.0 million with a weighted average interest rate of 5.55%, under a borrowing base of $210 million. The borrowing base availability has been reduced by $2.6 million in conjunction with a letter of credit issued at June 30, 2018.

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 its 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%, except that all borrowings will be an additional 0.25% per annum until the date the EBITDA ratio is calculated for the quarter ended September 30, 2018. Each such margin is based on the level of utilization under the borrowing base.

Secured Term Loan Agreement

In December 2014, Resolute and all 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. In January 2017, the Company repaid approximately $132 million constituting all amounts due under the Secured Term Loan Facility (including prepayment fees), with a portion of the proceeds from its common stock offering that closed on December 23, 2016. The Secured Term Loan Facility was terminated in connection with the repayment.

Senior Notes

In 2012, 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.

In May 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. The net proceeds of the offering of the Incremental Senior Notes, after reflecting the purchasers' discounts and commissions, and offering expenses, were approximately $125.1 million.

In April 2018, the Company consummated a private placement of senior notes totaling an additional $75 million aggregate principal amount of the Company's 8.50% Senior Notes due 2020 (the "Second Incremental Senior Notes"), under the same Indenture as the Original Senior Notes that were previously issued. The net proceeds of the offering of the Second Incremental Senior Notes, after reflecting the purchasers' discounts and commissions, and offering expenses, were approximately $73.9 million.

The Original Senior Notes, Incremental Senior Notes and Second Incremental Senior Notes (collectively referred to as 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, July 2017 and June 2018 the Company registered the exchange of the Original Senior Notes, the Incremental Senior Notes and the Second Incremental Senior Notes, respectively, with the SEC 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 Senior Notes have been exchanged for publicly 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 June 30, 2018.

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 at par. 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 June 30, 2018, was estimated to be $599.4 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 six months ended June 30, 2018 and 2017, differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% and 35%, respectively, to income before income taxes. This difference relates primarily to the valuation allowance established, in addition to state income taxes and estimated permanent differences.

There was no provision for income taxes during the three and six months ended June 30, 2018 and 2017.

The Company had no reserve for uncertain tax positions as of June 30, 2018 or December 31, 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 June 30, 2018 a valuation allowance should be established against the Company's deferred tax asset. The Company recorded a valuation allowance as of June 30, 2018 and December 31, 2017 of $198.8 million and $193.1 million, respectively, on its 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 Company’s Board of Directors (the “Board”). At June 30, 2018 and December 31, 2017, the Company had 62,500 shares of preferred stock issued and outstanding.

In October 2016, the Company entered into a preferred stock purchase agreement pursuant to which the Company issued and sold 62,500 shares of the Company’s 8 % Series B Cumulative Perpetual Convertible Preferred Stock, par value $0.0001 per share (the “Convertible Preferred Stock”).

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 of the Company, 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.

A preferred dividend of $1.3 million was declared on June 20, 2018, and paid on July 16, 2018, to holders of record at the close of business on July 1, 2018.

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. At June 30, 2018 and December 31, 2017, the Company had 23,181,746 and 22,527,652 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.

Long Term Employee Incentive Plan

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

In July 2009, the Company adopted the Incentive Plan, providing for long-term stock-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 stock-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 additional 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 six months ended June 30, 2018 and 2017, the Company recorded expense related to the Incentive Plan as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Time-based restricted stock awards	$2,195	$1,551	$5,669	$3,051
TSR awards	2,182	1,387	3,894	2,303
Stock option awards	112	39	3,776	496
Total stock-based compensation expense	4,489	2,977	13,339	5,850
Time-based restricted cash awards	375	627	1,657	906
Performance-based restricted cash awards	146	698	954	1,205
Cash-settled stock appreciation awards	(568)	(2,738)	8,683	1,903
Total cash-based compensation expense	(47)	(1,413)	11,294	4,014
Total Incentive Plan compensation expense	$4,442	$1,564	$24,633	$9,864

As of June 30, 2018, the Company holds unrecognized stock-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	$ 16,517	2.0
TSR awards	11,314	2.4
Stock option awards	216	0.7
Total unrecognized compensation expense	$ 28,047	

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Equity Awards

Equity awards consist of time-based and performance-based restricted stock and stock options under the Incentive Plan.

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 six months ended June 30, 2018, the Company granted 374,662 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 six months ended June 30, 2018:

	Shares	Weighted Average Grant Date Fair Value
Non-vested, beginning of period	407,487	$ 41.62
Granted	374,662	32.92
Vested	(182,274)	43.97
Forfeited	(12,470)	38.45
Non-vested, end of period	587,405	$ 35.41

The weighted average grant date fair value of shares granted during the six months ended June 30, 2018 and 2017 was $32.92 and $43.92, respectively.

TSR Awards

In February 2017 and 2018, 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 eleven peer companies in 2017 and fifteen companies in 2018. 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%
2018	35.19% - 197.75%	0%	1.96% - 2.31%

The following table summarizes the changes in non-vested TSR Awards for the six months ended June 30, 2018:

	Shares	Weighted Average Grant Date Fair Value
Non-vested, beginning of period	130,444	$ 77.23
Granted	184,657	58.87
Vested	(37,391)	65.90
Non-vested, end of period	277,710	$ 66.55

No outperformance shares were earned or vested during the six months ended June 30, 2018, related to the TSR awards granted in 2017.

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 six months ended June 30, 2018:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding, beginning of period	918,254	$ 3.95		
Exercised	(205,086)	3.64		
Forfeited	(5,292)	3.01		
Outstanding, end of period	707,876	$ 4.04	7.4	$ 19,225
Exercisable, end of period	528,613	$ 4.47	7.3	$ 14,132

No options were granted during the six months ended June 30, 2018. The total intrinsic value for options exercised during the six months ended June 30, 2018 and 2017 was $6.3 million and $2.0 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 272,084 rights outstanding as of June 30, 2018) and $2.915 per share (as to 1,121,162 rights outstanding as of June 30, 2018). 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 14% 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 June 30, 2018, was $41.1 million, of which $31.4 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 23% which will be updated periodically based on actual employee turnover. The total estimated future liability of the time-based restricted cash awards as of June 30, 2018 was $1.3 million, of which $0.4 million has been expensed.

Performance-Based Restricted Cash Awards

The performance criteria for the performance-based restricted cash awards granted in May 2015 were based on future prices of the Company’s common stock trading at or above specified thresholds. If and as certain stock price thresholds were met, using a 60 trading day average, various multiples of the performance-vested cash award were 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 were set forth in the governing agreements. As of May 2018, the final vesting date, all of the stock price hurdles up to $40.00 had previously been met. A time vesting element was applied to the performance-vested cash awards such that attained multiples were not 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 were satisfied. Once a time vesting date passed, the employee was entitled to be paid one third, two thirds or 100%, as applicable, of whatever multiples had been achieved provided the employee continued to be employed by the Company. The final payment of performance-based restricted cash was made in May 2018.

Note 8 — Derivative Instruments

Commodity 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 June 30, 2018, the fair value of the Company’s commodity derivatives was a net liability of $26.2 million (Level 2 fair value measurement).

The following tables represent Resolute’s commodity swap contracts as of June 30, 2018:

	Oil (NYMEX WTI)	
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl
Jul – Dec 2018	3,000	$ 50.56

	Gas (NYMEX Henry Hub)	
Remaining Term	MMBtu per Day	Weighted Average Swap Price per MMBtu
Jul – Oct 2018	20,000	$ 2.77

The following table represents Resolute’s two-way commodity collar contracts as of June 30, 2018:

	Oil (NYMEX WTI)		
Remaining Term	Bbl per Day	Weighted Average Floor Price per Bbl	Weighted Average Ceiling Price per Bbl
Jul – Dec 2018	2,000	$ 58.00	$ 63.96

The following table represents Resolute's three-way oil collar contracts as of June 30, 2018:

	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	3,500	$ 40.00	$ 49.29	$ 54.49

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The following table represents Resolute's commodity option contracts as of June 30, 2018:

	Oil (NYMEX WTI)		
Remaining Term	Bbl per Day	Weighted Average Bought Call Price per Bbl	Weighted Average Sold Call Price per Bbl
Jul – Dec 2018	2,200	$ —	$ 60.00
Jul – Dec 2018	1,100	55.00	—
Jan – Dec 2019	3,670	—	64.36

The following table represents Resolute's basis swap contracts as of June 30, 2018:

	Oil (Midland Argus)		Gas (Permian Basin El Paso)	
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	MMBtu per Day	Weighted Average Swap Price per MMBtu
Jul – Dec 2018	5,250	$ 5.68	18,000	$ 0.69

Subsequent to June 30, 2018, Resolute entered into additional oil and basis swap contracts as summarized below:

	Oil (NYMEX WTI)	
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl
Sep 2018 – Dec 2019	5,000	$ 64.54

	Oil (Midland Argus)	
Remaining Term	Bbl per Day	Weighted Average Price Differential per Bbl
Sep 2018 – Dec 2019	5,000	$ 10.37

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Other income (expense):				
Commodity derivative settlement gain (loss)	$(9,343)	$1,656	$(16,620)	$1,406

Mark-to-market gain (loss)	(2,777)	5,802	(4,902)	16,892
Commodity derivative instruments gain (loss)	$(12,120)	$7,458	$(21,522)	$18,298

Contingent Payment Derivative Instrument

In conjunction with the Aneth Field Sale in November 2017, Resolute is entitled to receive additional cash consideration of up to $35 million if index pricing targets, as defined in the Purchase and Sale Agreement, are achieved at specified future dates (see Note 3). The contingent consideration will be paid yearly if the pricing exceeds the thresholds pursuant to the Purchase and Sale Agreement. We have evaluated the contract and concluded that it meets the definition and requirements for accounting treatment as a derivative instrument. As of June 30, 2018, the fair value of the unearned additional consideration was $19.0 million. Fair value is determined through an application of mathematical models and Monte Carlo simulations designed to provide fair value estimates utilizing probability measures and the relevant market index measures. The fair value will be adjusted at each future reporting period over the life of the instrument. Changes in the fair value are included as a component of contingent payment derivative instrument gain (loss) on our consolidated statements of operations. See below for the location and fair value amounts of Resolute’s contingent payment derivative instrument reported in the consolidated balance sheet at June 30, 2018. The amount earned to date and included in accounts receivable is $6.8 million.

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

Resolute is exposed to credit risk to the extent of nonperformance by Elk Petroleum with respect to the contingent payment derivative discussed above. Elk Petroleum is contractually obligated to pay Resolute the earned contingent payments pursuant to the Purchase and Sale Agreement.

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 and contingent payment 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 June 30, 2018, and December 31, 2017 (in thousands):

	Level 2	
	June 30, 2018	December 31, 2017
Assets		
Commodity derivative instruments, current	$12,030	$ 526
Contingent payment derivative instruments, current	3,204	8,311
Contingent payment derivative instruments, long term	15,823	9,635
Total assets	$31,057	$ 18,472
Liabilities		
Commodity derivative instruments, current	$33,715	$ 20,822
Commodity derivative instruments, long term	4,503	990
Total liabilities	$38,218	$ 21,812

As all of the commodity derivative contracts by counterparty were in a net liability position as of June 30, 2018, the maximum amount of loss in the event of all counterparties defaulting was $0.

Note 9 —Revenue

ASC 606, Revenue from Contracts with Customers Adoption

The Company adopted ASC 606 as of January 1, 2018, utilizing the modified retrospective approach. The new revenue standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle of the guidance is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The guidance in the new standard supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the Industry Topics of the Codification.

The adoption of this standard had no impact on the Company's consolidated financial statements.

Revenue Recognition

Revenue from the sale of oil, gas and NGL is recognized when performance obligations are satisfied at the point control of the product is transferred to the customer, we have no further obligations to perform, the transaction price has been determined and collectability is reasonably assured. Payment is generally received in one to two months, depending on the product, after the sale has occurred. All of Resolute's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, basis or pricing differentials.

Oil Sales

The Company delivers oil to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title, and risk of loss of the product. The Company recognizes revenue when control transfers to the purchaser at the delivery point based on the contract specified price.

Gas and NGL Sales

The Company delivers gas and NGL contained within the gas which are extracted through processing the gas to a purchaser at the contract specified delivery point. The gas is transported from the wellhead to the delivery point specified in the contract. The gathering, compression and transportation charges related to moving the gas from the wellhead to the delivery point are recorded as lease operating expense in the condensed consolidated statement of operations. Once control is transferred at the delivery point, revenue is recognized based on the contract specified price. The purchaser processes the gas and remits proceeds to us for the resulting residue gas and NGL for the value of the residue gas and NGL at current market prices for each product as specified in the associated contract. The Company recognizes gas and NGL revenue based on the amount of the proceeds received from the purchaser, which is net of any required fees associated with processing the gas and extracting the NGL.

Disaggregation of Revenue

The following table details revenue by type and by geographic area/basin for the periods presented (in thousands):

	Three Months Ended June 30, 2018			Three Months Ended June 30, 2017		
	Permian Basin	Paradox Basin	Total	Permian Basin	Paradox Basin	Total
Revenue:						
Oil	$58,395	$ —	$58,395	$39,132	$21,571	$60,703
Gas	5,670	—	5,670	6,285	183	6,468
Natural gas liquids	9,315	—	9,315	3,089	—	3,089
Total revenue all products	$73,380	$ —	$73,380	$48,506	$21,754	$70,260

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
	Permian Basin	Paradox Basin	Total	Permian Basin	Paradox Basin	Total
Revenue:						
Oil	$118,046	$ —	$118,046	$73,701	$44,661	$118,362
Gas	$12,030	—	12,030	10,365	454	10,819
Natural gas liquids	18,022	—	18,022	5,671	—	5,671
Total revenue all products	$148,098	$ —	$148,098	$89,737	$45,115	$134,852

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606 which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. For the Company's product sales that have a contract term of one year or less, we have utilized the practical expedient in ASC 606, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Contract Balances

Under the Company's product sales contracts, the Company invoices customers once the performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under ASC 606. At June 30, 2018 and December 31, 2017, the Company's receivables from contracts with customers were $41.8 million and $43.1 million, respectively.

Note 10 — Related Parties

In May 2018, the Company and Monarch Alternative Capital LP ("Monarch") entered into a settlement agreement (the "Settlement Agreement") regarding nominations to the Company's Board and related matters. The Settlement Agreement provides for, among other things, the expansion of the size of the Board from eight members to eleven members and the appointment to the Board of Joseph Citarrella, Managing Principal of Monarch, Wilkie S. Colyer, Jr., Principal of Goff Capital, Inc., and Robert J. Raymond, founding member and portfolio manager of RR Advisors, LLC d/b/a RCH

Energy, effective as of May 15, 2018. Pursuant to the Settlement Agreement, the Company reimbursed Monarch $0.4 million for fees and expenses incurred in connection with the Settlement Agreement and related prior activities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further details related to the Settlement Agreement.

Robert J. Raymond is a member of Resolute's Board. Mr. Raymond's brother, Colin Raymond, is the Chief Executive Officer of Compass Well Services ("Compass"), which performs certain oilfield services in the Permian Basin for Resolute Natural Resources Company, LLC. An affiliate of RR Advisors, LLC, of which Mr. Raymond is the sole member, holds a non-controlling ownership interest in Compass. Additionally, each of Mr. Raymond's father, Lee Raymond, his brothers, Colin and John Raymond, hold a non-controlling ownership interest in Compass. For the three months ended June 30, 2018 and 2017, the Company made payments in the amounts of approximately $2.3 million and $1.0 million, respectively, to Compass in exchange for such services. For the six months ended June 30, 2018 and 2017, the Company made payments in the amount of approximately $3.6 million and $1.6 million, respectively. Included in accounts payable was $0.4 million and $0.1 million due to Compass as of June 30, 2018 and December 31, 2017, respectively.

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 Form 10-K, 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 in the Delaware Basin in west Texas. Our development activity is focused on our 27,100 gross (21,100 net) operated acreage, approximately 90% of which is located 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 to pursue opportunistic acquisitions in the Permian Basin, and thus drive long-term stockholder value.

Resolute's 2018 development plan includes anticipated net capital spending of $365 million to $395 million, including $350 million to $375 million in drilling and completion capital to support two rigs throughout the year, and a third rig which commenced work in late February and is expected to be released by mid-September. Additionally, the Company expects to spend an incremental $42 million to $49 million on field facilities and other corporate capital, and to receive estimated earn-out payments of $27 million to $29 million from Caprock and $10 million in additional contingent consideration relating to the Aneth Field Sale. Overall, Resolute expects to drill 42 wells during the year, bring 38 wells on production, carry six drilled but uncompleted wells ("DUCs") and have two wells drilling over year-end 2018.

Each of the three rigs primarily is pad drilling three-well stacks with all the rigs often in the same spacing unit at the same time. Our operations focus in the Sandlot unit in Mustang and the Mitre/Ranger units in Appaloosa, with Wolfcamp Upper A, Lower A, and Upper B as the primary target zones and also sometimes including Lower Wolfcamp zones. This approach to pad drilling provides us with the opportunity to batch complete groups of up to nine wells simultaneously.

Beginning in late 2017, the Company shifted focus to building an inventory of drilled wells to batch complete. Two completions occurred in the first quarter of 2018, and in mid-March we began completing our first nine pack group in the Ranger unit. The Ranger nine pack group came online in June and the Sandlot nine pack group came online in July. Further groups of completed wells are expected to come online throughout the remainder of the year. We anticipate production growth to accelerate in the second half of the year.

This 2018 development plan was put in place based on the Company's experience with the impact of infill drilling on well performance. The Company's estimates of 2018 total production incorporate anticipated effects of frac interference on older wells, the expected reduced production from newly drilled infill wells and potential operational events that could reduce production further such as power outages, weather, well shut-ins and downstream gas constraints. The Company regularly reviews the effects of all of these factors as it evaluates projections of future production.

In February 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.

In April 2017, Resolute Natural Resources LLC ("Resolute Southwest") entered into a Crude Oil Connection and Dedication Agreement with Caprock Permian Crude LLC ("Caprock Crude"), an affiliate of Caprock Permian Processing LLC and Caprock Field Services LLC (collectively "Caprock"). Pursuant to the agreement, Caprock

Crude constructed 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 $1.75 that covers the joint tariff payable to Caprock Crude under the Crude Oil Connection and Dedication Agreement.

In May 2017, Resolute Southwest closed on a Purchase and Sale Agreement with CP Exploration II, LLC and Petrocap CPX, LLC pursuant to which Resolute Southwest acquired certain producing and undeveloped oil and gas properties in the Delaware Basin in Reeves County, Texas. 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.

In November 2017, Resolute closed on a Purchase and Sale Agreement pursuant to which we sold the equity interests in Resolute Aneth, LLC (the "Aneth Field Sale"), the entity which held all of Resolute's interest in Aneth Field, and certain other assets associated with Aneth Field operations, to Elk Petroleum. Total consideration will be up to $195 million, comprised of $160 million received at closing (adjusted for normal closing purchase price adjustments) and up to an additional $35 million if oil prices exceed certain levels in the three years following the closing. The historical results of operations of the Aneth Field Properties prior to disposition are contained in our financial position and results as of December 31, 2017.

How We Evaluate Our Operations

We use 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 expense, general and administrative expense, cash-based general and administrative expense, operating cash flow, Adjusted net income (loss), Adjusted EBITDA and Credit facility 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 implement exploitation activities that can increase production or diminish production declines relative to what would have been the case without intervention.

The price of oil has generally trended upward since the latter half of 2017 and through the second quarter of 2018. However, in our area of operation, the Permian Basin has been characterized by periods when production has exceeded the local transportation capacity, resulting in a substantial difference between the price we receive for our oil and gas production and the benchmark prices. For example, oil basis differentials widened to as much as $9.50 per barrel in June and $13.23 in August 2018. The Midland-Cushing ("Mid-Cush") basis differential for the second quarter of 2018 averaged $5.15 per barrel. We expect that volatility to continue. The expansion and construction of Permian pipeline facilities, which are schedule for 2019 and 2020, are affected by the availability and costs of necessary equipment, supplies, labor and other services, as well as the length of time to complete such projects. In addition, these projects can be affected by changes in international trade relationships, including the imposition of trade restrictions or tariffs relating to crude oil and natural gas and any materials or products used to expand or construct pipeline facilities. All of these factors could negatively impact our realized oil and gas prices, as well as actual results of our operations.

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 wells in the Wolfcamp formation. 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, 2017, we had estimated net total proved Delaware Basin reserves of 53,428 MBoe. For the six months ended June 30, 2018, the 2018 drilling program has resulted in significant increases to those reserves through the addition of ten proved and one proved undeveloped location, and the conversion of two locations from proved undeveloped to developed.

Operating Expenses. Operating expense consist of costs associated with the operation of oil and gas properties and production and ad valorem taxes. Compression, gathering, water disposal, utilities, direct labor, repair and maintenance, workovers, rental equipment, fluids and chemicals and contract services comprise the most significant portion of lease operating expense. We monitor our operating expense 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, compressor, gathering, water disposal 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 prices 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 expense 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 expense includes, among other things, salaries and benefits, long-term incentive 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 stockholder reports, investor relations activities, registrar and transfer agent fees, director and officer liability insurance costs and director compensation.

Cash-based General and Administrative Expense. We define cash-based general and administrative expense (a non-GAAP measure) as consolidated general and administrative expense adjusted to exclude non-cash stock-based compensation expense and one-time, non-recurring, transaction-related and other expenses.

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 expense.

Adjusted Net Income (Loss). Adjusted net income (loss) (a non-GAAP measure) is equivalent to net income (loss) excluding non-cash items identified as affecting comparability of earnings between periods, which are non-cash mark-to-market (gains) losses on commodity and contingent payment derivative instruments, non-cash stock-based compensation expense related to the acceleration of vesting of long-term incentive awards to employees terminated as a result of the Aneth Field Sale and stockholder activism expenses.

Adjusted EBITDA. We define Adjusted EBITDA (a non-GAAP measure) as consolidated net income adjusted to exclude interest expense, interest income, income taxes, depletion, depreciation and amortization, one-time costs of the Aneth Field Sale, costs related to stockholder activism, non-cash stock-based compensation expense, non-cash change in fair value of cash-settled incentive awards, non-recurring cash-settled incentive award payments, change in fair value of derivative instruments, gains and losses on the sale of assets and ceiling write-down of oil and gas properties.

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:

- our operating performance and return on capital without regard to financing methods or capital structure;
- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our ability to finance capital expenditures;
- the ability of our assets to generate cash sufficient to support our indebtedness and pay interest costs; and
- the viability of acquisitions and capital expenditures and the overall rates of return on alternative investment opportunities.

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 stock-based compensation expense, non-cash change in fair value of cash-settled incentive awards, customary costs and expenses incurred related to acquisitions or dispositions (including, without limitation, legal, accounting and financial advisory fees, title and environmental due diligence costs, employee retention, severance, or relocation expenses, costs and expenses related to the acceleration of long-term employee incentive awards, and contract termination costs) and stockholder activism related costs and expenses. Credit facility EBITDA for the period ending on June 30, 2018 is equal to EBITDA for the period beginning on October 1, 2017 and ending on June 30, 2018, divided by three multiplied by four. 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. Credit facility EBITDA is used as a supplemental liquidity or performance measure by our management and by external users of our financial statements such as our bank syndicate, primarily to assess the ability of our assets to generate cash sufficient to support our indebtedness and pay interest costs and to measure compliance with the covenants in our Revolving Credit Facility.

Adjusted net income (loss), Adjusted EBITDA and Credit facility EBITDA should not be considered as alternatives to, or more meaningful than, net income (loss) available to common stockholders, net income (loss), operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with accounting 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 (loss) and net cash provided by operating activities determined under GAAP, as well as Adjusted EBITDA and Credit facility EBITDA, when evaluating our financial performance and liquidity. Adjusted EBITDA and Credit facility 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. Adjusted EBITDA and Credit facility EBITDA as we calculate those numbers may not be comparable to EBITDA measures of any other company because other entities may not calculate those measures in the same manner.

Permian Basin Properties

As of December 31, 2017, we had interests in approximately 27,100 gross (21,100 net) acres in the Permian Basin of Texas. Our principal project area located in the Delaware Basin portion of the Permian Basin, in northern Reeves County, targets the Wolfcamp formation (the "Delaware Basin Wolfcamp Project"). Our development activity in the Delaware Basin Wolfcamp Project is focused on our 23,600 gross (18,700 net) acreage position. Based on drilling activity as of December 31, 2017, approximately 89% of the gross acreage is held by production. We are currently evaluating the 3,500 gross acres and 2,400 net acres we acquired in the Delaware Basin Bronco Acquisition in southern Reeves County for drilling opportunities in the Wolfcamp, Woodford and Barnett formations.

During the six months ended June 30, 2018, we completed 13 gross (11.9 net) wells and had 13 gross (10.6 net) wells awaiting completion at quarter end. Furthermore, as of June 30, 2018, we were in the process of drilling 15 gross (13.6 net) wells. All such wells are located in the Delaware Basin.

Aneth Field Properties

Aneth Field accounted for 20% of our production during 2017, averaging 4,974 Boe per day, of which 96% was oil.

In November 2017 we completed the sale of our Aneth Field Properties for total consideration of up to $195 million, comprised of $160 million received at closing, adjusted for normal closing purchase price adjustments, and up to an additional $35 million if oil prices exceed certain levels in the three years following the closing. Through June 30, 2018, $6.8 million of the additional $35 million has been earned.

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 and gas prices, basis differentials, 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. Basis differentials have recently increased and are expected to further increase in the future. Sustained periods of low realized prices for oil and gas 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 primarily by developing existing properties. 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.

Settlement Agreement

In February 2018, Monarch Energy Holdings, LLC and certain of its affiliates (together, "Monarch") submitted a nomination notice to the Company, nominating Joseph Citarrella, Patrick Bartels and Samuel Langford for election to our Board of Directors (the "Board") at our 2018 annual meeting of stockholders (the "2018 Annual Meeting"). In March 2018, Monarch filed a preliminary proxy statement with the SEC that included Monarch's proposal for the election of Messrs. Citarrella, Bartels and Langford to our Board.

In May 2018, the Company and Monarch entered into a settlement agreement (the "Settlement Agreement") regarding nominations to the Company's Board and related matters. The Settlement Agreement provides for, among other things, (i) the expansion of the size of the Board from eight members to eleven members and the appointment to the Board of Mr. Citarrella, Managing Principal of Monarch, Wilkie S. Colyer, Jr., Principal of Goff Capital, Inc., and Robert J. Raymond, founding member and portfolio manager of RR Advisors, LLC d/b/a RCH Energy, effective as of May 15, 2018, and (ii) the Company's agreement to seek stockholder approval at the 2018 Annual Meeting, to amend the Company's certificate of incorporation (the "Certificate of Incorporation") to provide for the declassification of the Board, which was subsequently approved at the 2018 Annual Meeting. Pursuant to the Certificate of Incorporation, each director elected at the 2018 Annual Meeting and each director elected at each future annual meeting was and will be elected for a one-year term such that commencing with the Company's 2020 annual meeting of stockholders, all directors standing for election at such meeting will be elected for one-year terms. Mr. Citarrella serves in the class of directors with terms expiring at the Company's 2019 annual meeting of stockholders (the "2019 Annual Meeting"), and Messrs. Colyer and Raymond serve in the class of directors with terms expiring at the Company's 2020 annual meeting of stockholders. Also pursuant to the Settlement Agreement, prior to the 2019 Annual Meeting, the Board will not be expanded to greater than eleven directors without the approval of the Monarch director designee.

Monarch also agreed to (i) withdraw its previously announced nominations of Messrs. Citarrella, Bartels and Langford to the Board and (ii) abide by certain customary standstill obligations (subject to customary exceptions) until the date of the 2019 Annual Meeting, or under certain circumstances, such earlier date as defined under the Settlement Agreement. The Settlement Agreement, including the standstill restrictions, will terminate on the day of the 2019 Annual Meeting unless Monarch elects to terminate the Settlement Agreement at any time from and after the tenth business day prior to the expiration date of the Company's advance notice period for the nomination of directors at the 2019 Annual Meeting (an "Investor Termination"). In the event of an Investor Termination, the Monarch director designee will resign immediately upon, and as a condition to, the effectiveness of such termination. Pursuant to the Settlement Agreement, the Company reimbursed Monarch $0.4 million for fees and expenses incurred in connection with the Settlement Agreement and related prior activities.

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 six months ended June 30, 2018, in comparison to results for the three and six months ended June 30, 2017.

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net Sales:				
Oil (MBbl)	974	1,400	1,951	2,613
Gas (MMcf)	3,770	2,881	7,226	4,803
NGL (MBbl)	585	336	1,147	576
Total sales (MBoe)	2,187	2,216	4,302	3,989
Average daily sales (Boe/d)	24,036	24,355	23,769	22,041
Average Sales Prices:				
Oil ($/Bbl)	$59.96	$43.36	$60.51	$45.29
Gas ($/Mcf)	1.50	2.24	1.66	2.25
NGL ($/Bbl)	15.92	9.19	15.71	9.85
Average sales price ($/Boe, excluding commodity derivative settlements)	$33.55	$31.70	$34.42	$33.80
Operating Expenses ($/Boe):				
Lease operating	$7.02	$8.97	$6.28	$9.59
Production and ad valorem taxes	2.52	2.51	2.57	2.89
General and administrative	7.26	4.27	8.59	4.98
Cash-based general and administrative	5.20	2.95	5.49	3.54
Cash-settled incentive awards	(0.02)	(0.64)	2.63	1.01
Depletion, depreciation, amortization and accretion	10.74	10.08	10.93	9.62

Quarter Ended June 30, 2018, Compared to the Quarter Ended June 30, 2017

Revenue. Revenue from oil and gas activities increased by 4% to $73.4 million during 2018, from $70.3 million during 2017. The increase in revenue was primarily attributable to increased commodity pricing ($33.55 per Boe in 2018 versus $31.70 per Boe in 2017). Sales volumes decreased to 2,187 MBoe during 2018 as compared to 2,216 MBoe during 2017, principally as a result of the 2017 Aneth Field Sale, offset by production from newly drilled and completed wells in the Delaware Basin. Pro forma for the 2017 Aneth Field Sale, 2018 production increased 31%.

Operating Expenses. Operating expense includes compression, gathering, water disposal, utilities, direct labor, contract services, field office rent, production and ad valorem taxes, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, workover expenses and other customary charges. Workover expenses will fluctuate based upon the amount of any maintenance and remedial activity performed during the period. Resolute assesses lease operating expense in part by monitoring the expense in relation to production volumes and the number of wells operated.

Lease operating expense decreased 23% to $15.4 million during 2018, from $19.9 million during 2017. On a per-unit basis, lease operating expense decreased 22% to $7.02 per Boe in 2018 compared to $8.97 per Boe in 2017. The decrease in per-unit operating expense was primarily due to the Aneth Field Sale (Aneth Field had significantly higher operating costs as compared to our Delaware Basin properties) as well as the increase in production from wells in the Delaware Basin. The decrease was partially offset by a $1.5 million increase in workover expenses in the Delaware Basin during the 2018 period.

Production and ad valorem taxes remained relatively unchanged at $5.5 million, or $2.52 per Boe, during 2018, as compared to $5.6 million, or $2.51 per Boe, during 2017. Production and ad valorem taxes were 7.5% of total revenue in 2018 versus 7.9% of total revenue in 2017. The lower production and ad valorem taxes as a percentage of revenue in 2018 as compared to 2017 was primarily the result of the Aneth Field Sale. All revenue in 2018 was recognized in the state of Texas, which has a lower tax rate than the Aneth Field Properties in Utah, which were included in 2017 results.

General and administrative expense includes, among other things, salaries and benefits, long-term incentive 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 stockholder reports, investor relations activities, registrar and transfer agent fees, director and officer liability insurance costs and director compensation. 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 add value to our asset base.

General and administrative expense was comprised of the following during the quarters ended June 30, 2018 and 2017:

	Three Months Ended June 30,	
	2018	2017
Stockholder activism costs	$3,085	$—
Recurring stock-based compensation	4,489	2,934
Other recurring costs	8,301	6,538
Total general and administrative expense	$15,875	$9,472

General and administrative expense increased to $15.9 million during 2018, as compared to $9.5 million during 2017. The $6.4 million, or 68% increase, primarily resulted from approximately $3.1 million in stockholder activism costs during the 2018 quarter. Additionally, certain overhead reimbursements, which reduce general and administrative expense, decreased $2.2 million period over period, also as a result of the Aneth Field Sale. On a per-unit basis, general and administrative expenses increased to $7.26 per Boe in 2018 from $4.27 per Boe in 2017. Excluding stock-based compensation and stockholder activism expenses, which management believes is a more representative measure of the cost to run the ongoing business, cash-based general and administrative expense was $8.3 million, or $3.79 per Boe, in 2018 compared to $6.5 million, or $2.95 per Boe, in 2017. This $1.8 million, or 28 percent increase, primarily resulted from the $2.2 million decrease in certain overhead reimbursements noted above, offset by $0.4 million in other reductions in general and administrative expense.

Cash-settled incentive awards expense relates to the 2015 and 2016 grants 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 vest and are expensed ratably over three years. The performance-based awards and stock appreciation rights vest ratably over three years but their fair value is re-measured at each period end over their ten-year lives. Cash-settled incentive award expense increased by $1.3 million to a credit of less than $0.1 million in 2018, as compared to a credit of $1.4 million in 2017. This increase was the result of a change in the fair value related to the grant of cash-settled stock appreciation rights under the long-term incentive program. Actual cash payments during the 2018 period were $8.2 million, which includes the final payment of the performance-based restricted cash awards.

Depletion, depreciation, amortization and accretion expense increased to $23.5 million during 2018, as compared to $22.3 million during 2017. On a per-unit basis, depreciation and amortization expenses also increased to $10.74 per Boe in 2018 compared to $10.08 per Boe in 2017. The increase on a per-unit basis was attributable to capitalized costs increasing by a greater percentage than the associated proved reserve quantities period over period.

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, 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 has been recorded since March 2016. If in future periods a negative factor affects 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 2018, the loss on oil and gas commodity derivatives was $12.1 million, consisting of $2.8 million of mark-to-market losses and $9.3 million of derivative settlement losses. During 2017 the gain on oil and gas commodity derivatives was $7.5 million, consisting of $5.8 million of mark-to-market gains and $1.7 million of derivative settlement gains.

Interest expense in 2018 decreased to $8.5 million from $8.8 million recorded in 2017. The decrease in interest expense was primarily due to an increase in the amount of capitalized interest partially offset by an increase in the amount of interest on the Senior Notes due to the incremental Senior Note issuances. The components of our interest expense are as follows (in thousands):

	Three Months Ended June 30,	
	2018	2017
8.50% senior notes	$12,608	$9,946
Revolving credit facility	844	989
Amortization of deferred financing costs and senior notes premium	613	520
Bridge facility commitment fee and other, net	5	991
Capitalized interest	(5,555)	(3,667)
Total interest expense	$8,515	$8,779

Income Tax Benefit (Expense). No income tax benefit or expense was recognized during the three months ended June 30, 2018 and 2017 due to the deferred tax asset valuation allowance previously established by the Company.

Six Months Ended June 30, 2018, Compared to the Six Months Ended June 30, 2017

Revenue. Revenue from oil and gas activities increased by 10% to $148.1 million during 2018, from $134.9 million during 2017. Of the $13.2 million increase in revenue, approximately $10.6 million was attributable to increased production and $2.6 million was attributable to increased commodity pricing ($34.42 per Boe in 2018 versus $33.80 per Boe in 2017). Sales volumes increased 8% to 4,302 MBoe during 2018 as compared to 3,989 MBoe during 2017, principally as a result of production from newly drilled and completed wells in the Delaware Basin. Pro forma for the Aneth Field Sale, production increased 48%.

Operating Expenses. Lease operating expenses decreased to $27.0 million during 2018, from $38.2 million during 2017. On a per-unit basis, lease operating expense decreased 34% to $6.28 in 2018 compared to $9.59 in 2017. The decrease in per-unit operating expense is primarily due to the Aneth Field Sale (Aneth Field had significantly higher operating costs as compared to our Delaware Basin properties) as well as the increase in production from wells in the Delaware Basin. The decrease was partially offset by a $1.6 million increase in workover expenses in the Delaware Basin during the 2018 period.

Production and ad valorem taxes decreased to $11.1 million during 2018, as compared to $11.5 million during 2018. On a per-unit basis, production and ad valorem taxes decreased to $2.57 per Boe in 2018 as compared to $2.89 per Boe in 2017. Production and ad valorem taxes were 7.5% of total revenue in 2018 versus 8.6% of total revenue in 2017. The lower production and ad valorem taxes as a percentage of revenue in 2018 as compared to 2017 is primarily the result of the Aneth Field Sale. All revenue in 2018 was recognized in the state of Texas, which has a lower tax rate than the Aneth Field Properties in Utah, which were included in 2017 results.

General and administrative expense was comprised of the following during the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30,	
	2018	2017
Stock-based Aneth transaction costs	$6,014	$—
Stockholder activism costs	6,386	—
Recurring stock-based compensation	7,325	5,753
Other recurring costs	17,217	14,134
Total general and administrative expense	$36,942	$19,887

General and administrative expense increased to $36.9 million during 2018, as compared to $19.9 million during 2017. The $17.0 million, or 86% increase, primarily resulted from $6.4 million in stockholder activism costs during the six months ended June 30, 2018. The Company also incurred a one-time, non-cash increase of $6.0 million in stock based compensation expense due to the modification and accelerated vesting of long-term incentive awards to employees terminated as a result of the Aneth Field Sale. The vesting terms of the outstanding long-term awards for affected employees was accelerated and recognized in the first quarter of 2018. Additionally, certain overhead reimbursements, which reduce general and administrative expense, decreased period over period, also as a result of the Aneth Field Sale. On a per-unit basis, general and administrative expenses increased to $8.59 per Boe in 2018 from the $4.98 per Boe in 2017. Excluding stock-based compensation and stockholder activism expenses, which management believes is a more representative measure of the cost to run the ongoing business, cash-based general and administrative expense was $17.2 million, or $4.00 per Boe, in 2018 compared to $14.1 million, or $3.54 per Boe, in 2017.

Cash-settled incentive awards were comprised of the following during the six months ended June 30, 2018 and 2017:

	Six Months Ended June 30,	
	2018	2017
Accrual of Aneth transaction cash-settled incentive awards	$7,260	$—
Recurring cash-settled incentive awards	4,034	4,014
Total cash-settled incentive awards	$11,294	$4,014

Cash settled incentive award expense increased by $7.3 million to $11.3 million in 2018, as compared to $4.0 million in 2017. The $7.3 million increase resulted from the modification of 2018 long-term incentive awards as a result of the Aneth Field Sale. The vesting of these awards was accelerated for affected employees and the expense was recognized during the first quarter of 2018. Actual cash payments during the 2018 period were $14.4 million, which includes the final payment of the performance-based restricted cash awards.

Depletion, depreciation, amortization and accretion expenses increased to $47.0 million during 2018, as compared to $38.4 million during 2017, partially as a result of the 8% increase in production period over period. On a per-unit basis, depletion, depreciation, amortization and accretion expenses increased to $10.93 per Boe in 2018 from $9.62 per Boe in 2017. The increase on a per-unit basis was attributable to capitalized costs increasing by a greater percentage than the associated proved reserve quantities period over period.

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. No impairment has been recorded since March 2016. If in future periods a negative factor affects 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 2018 the loss on oil and gas commodity derivatives was $21.5 million, consisting of $4.9 million of mark-to-market losses and $16.6 million of derivative settlement losses. During 2017 the gain on oil and gas commodity derivatives was $18.3 million, consisting of $16.9 million of mark-to-market gains and $1.4 million of derivative settlement gains.

Interest expense in 2018 decreased to $16.1 million from the $26.5 million recorded in 2017. The decrease in interest expense was primarily due to the termination of the Secured Term Loan Facility and bridge facility in 2017, partially offset by increased interest expense on the Senior Notes and Revolving Credit Facility. The components of our interest expense are as follows (in thousands):

	Six Months Ended June 30,	
	2018	2017
8.50% senior notes	$23,765	$18,446
Secured term loan facility	—	3,631
Revolving credit facility	1,997	1,303
Amortization of deferred financing costs, senior notes premium	1,150	8,263

and secured term loan facility discount		
Bridge facility commitment fee and other, net	6	1,004
Capitalized interest	(10,835)	(6,171)
Total interest expense	$16,083	$26,476

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.

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Income Tax Benefit (Expense). No income tax benefit or expense was recognized during the six months ended June 30, 2018 and 2017 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 six months ended June 30, 2018 and 2017.

	Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Cash provided by operating activities	$60,289	$52,159
Cash used in investing activities	(175,042)	(261,869)
Cash provided by financing activities	111,806	77,720
Net decrease in cash and cash equivalents	$(2,947)	$(131,990)

Net cash provided by operating activities was $60.3 million in 2018 as compared to $52.2 million for the 2017 period. The increase in net cash provided by operating activities in 2018 as compared to 2017 was primarily due to increased revenue and lower lease operating expense offset by an increase in commodity derivative settlement losses.

Net cash used in investing activities was $175.0 million in 2018 compared to $261.9 million in 2017. The primary investing activity in 2018 was cash used for capital expenditures of $180.7 million. Capital expenditures in 2018 consisted primarily of drilling activities and infrastructure projects in the Permian Basin, offset by $7.7 million in proceeds from the sale of property and equipment due principally to Caprock earn-out payments. The primary investing activities in 2017 were cash used for acquisitions of $161.3 million and capital expenditures of $118.5 million. Capital expenditures in 2017 consisted primarily of drilling activities and infrastructure projects in the Permian Basin. Capital divestitures in 2017 included $13.1 million of net proceeds primarily from the sale of the New Mexico Properties and $6.1 million of cash receipts related to Caprock earn-out payments.

Net cash provided by financing activities was $111.8 million in 2018 compared to $77.7 million used in 2017. The primary financing activities in 2018 were $43 million in net borrowings under the Revolving Credit Facility and approximately $74.6 million of proceeds from the issuance of the Second Incremental Senior Notes. The primary financing activities in 2017 were $126.9 million of proceeds received from the issuance of the Incremental Senior Notes and $90 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 (see Senior Notes below, for a discussion of the April 2018 private placement of $75 million in debt securities) or from other sources, such as asset sales. There can be no assurance that needed capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our Revolving Credit Facility or Senior Notes. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to satisfy our obligations under our existing indebtedness, finance the capital expenditures necessary to maintain production or proved reserves or complete acquisitions that may be favorable to us.

We plan to continue our practice of hedging a significant portion of our production with respect to both the WTI Index price and Mid-Cush differential for oil and the Henry Hub index price and El Paso Permian differential for gas, 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.

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 June 30, 2018.

Revolving Credit Facility

In March 2018, we entered into the Third Amendment to the Third Amended and Restated Credit Agreement. The Third Amendment, among other things, amended the definition of Applicable Margin so that if the ratio of total funded debt to EBITDA for the period ending June 30, 2018 exceeds 4.00:1.00, then each applicable rate per annum shall be increased by 0.25% per annum until the date such ratio is calculated for the quarter ending September 30, 2018. It also amended the definition of EBITDA to include certain costs incurred by the Company in connection with activist investor campaigns and provides for certain amendments to the calculation of EBITDA, and amended the covenant governing the ratio of funded debt to EBITDA. Lastly, the Third Amendment also provided that the borrowing base shall automatically be reduced by 25% of all unsecured indebtedness of the Company in excess of $600 million. In April 2018, the borrowing base was reaffirmed at $210.0 million. We were in compliance with the terms and covenants of the Revolving Credit Facility at June 30, 2018.

The Revolving Credit Facility specifies a maximum borrowing base as determined by the lenders' sole discretion. 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 includes covenants that require, among other things, Resolute to maintain a ratio of current assets to current liabilities of no less than 1.00 to 1.00 and a ratio of funded debt to EBITDA (as defined in the Revolving Credit Facility) of no more than 4.25 to 1.00 for the second quarter of 2018 and 4.00 to 1.00 for the third and fourth quarter of 2018. 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.

As of June 30, 2018, outstanding borrowings under the Revolving Credit Facility were $73.0 million with a weighted average interest rate of 5.55%, under a borrowing base of $210 million. The borrowing base availability has been reduced by $2.6 million in conjunction with a letter of credit issued at June 30, 2018.

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 its wholly-owned subsidiaries.

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 the 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. In January 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 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 of the Company’s 8.50% Senior Notes due 2020 (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 notes payable semiannually in cash on May and November 1 of each year.

In May 2017, we 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. The net proceeds of the offering of the Incremental Senior Notes, after reflecting the purchasers' discounts and commissions, and offering expenses, were approximately $125.1 million.

In April 2018, we consummated a private placement of senior notes totaling an additional $75 million aggregate principal amount of the Company's 8.50% Senior Notes due 2020 (the "Second Incremental Senior Notes"), under the same indenture as the Original Senior Notes that were previously issued. The net proceeds of the offering of the Second Incremental Senior Notes, after reflecting the purchasers' discounts and commissions, and offering expenses, were approximately $73.9 million.

The Original Senior Notes, Incremental Senior Notes and the Second Incremental Senior Notes (collectively referred to as the "Senior Notes") were issued under an Indenture (the "Indenture") among the Company and all of the Company's subsidiaries (the "Guarantors"), 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, July 2017 and June 2018, we registered the exchange of the Original Senior Notes, the Incremental Senior Notes and the Second Incremental Senior Notes, respectively, with the SEC pursuant to the 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 Senior Notes have been exchanged for publicly registered Senor Notes. 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 June 30, 2018.

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 at par. If a change of control occurs, each holder of the Senior Notes will have the right to require that we purchase all of such holder's Senior Notes in an amount equal to 101% of the principal of such Senior Notes, plus accrued and unpaid interest, if any, to the date of the purchase.

Preferred Stock

In October 2016, the Company entered into a preferred stock purchase agreement, pursuant to which the Company issued and sold 62,500 shares of the Company's 8 % Series B Cumulative Perpetual Convertible Preferred Stock, par value $0.0001 per share (the "Convertible Preferred Stock"), 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 of the Company, 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.

A preferred dividend of $1.3 million was declared on June 20, 2018, and paid on July 16, 2018, to holders of record at the close of business on July 1, 2018.

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.

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 fixed price swaps, basis swaps, option contracts, two- and three-way collars and other such agreements. The purpose of these instruments is to manage our exposure to commodity price risk in order to provide a measure of stability to our cash flows in an environment of volatile oil and gas prices.

Under the terms of our Revolving Credit Agreement, the form of derivative instruments to be entered into is at our discretion, but they are not to exceed (i) for the first year, the greater of 85% of our anticipated 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 production from proved properties or 85% of our anticipated production from proved developed producing properties after such two year period, utilizing economic parameters specified in our credit agreement, including escalated prices and costs.

By removing the price volatility from a significant portion of our oil and gas production, we have mitigated, but not eliminated, the potential effects of volatile prices on cash flow from operations for the periods hedged. While mitigating negative effects of falling commodity prices or increases in basis differentials, 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 June 30, 2018, the fair value of our commodity derivatives was a net liability of $26.2 million.

The following table represents our oil swap contracts as of June 30, 2018:

	Oil (NYMEX WTI)		
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jul – Dec 2018	3,000	$ 50.56	$ (10,976)

The following table represents our gas swap contracts as of June 30, 2018:

	Gas (NYMEX Henry Hub)		
Remaining Term	MMBtu per Day	Weighted Average Swap Price per MMBtu	Fair Value of Asset (Liability)

				(in thousands)
Jul – Oct 2018	20,000	$ 2.77		$ (408)

The following table represents our two-way oil collar contracts as of June 30, 2018:

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)
Jul – Dec 2018	2,000	$ 58.00	$ 63.96	$ (2,724)

The following table represents our three-way oil collar contracts as of June 30, 2018:

Oil (NYMEX WTI)					
Remaining Term	Bbl per Day	Weighted Average Short Put Price per Bbl	Weighted Average Floor Price per Bbl	Weighted Average Ceiling Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jul – Dec 2018	3,500	40.00	$ 49.29	$ 54.49	$ (10,409)

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The following table represents our commodity option contracts as of June 30, 2018:

	Oil (NYMEX WTI)			
Remaining Term	Bbl per Day	Weighted Average Bought Call Price per Bbl	Weighted Average Sold Call Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jul – Dec 2018	2,200	$ —	$ 60.00	$ (4,610)
Jul – Dec 2018	1,100	55.00	—	3,201
Jan – Dec 2019	3,670	—	64.36	(9,091)

The following table represents Resolute's basis swap contracts as of June 30, 2018:

	Oil (Midland Argus)		
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl	Fair Value of Asset (Liability) (in thousands)
Jul – Dec 2018	5,250	$ 5.68	$ 6,553

	Gas (Permian Basin El Paso)		
Remaining Term	MMBtu per Day	Weighted Average Swap Price per MMBtu	Fair Value of Asset (Liability) (in thousands)
Jul – Dec 2018	18,000	$ 0.69	$ 2,276

Subsequent to June 30, 2018, we entered into additional oil and basis swap contracts as summarized below:

	Oil (NYMEX WTI)	
Remaining Term	Bbl per Day	Weighted Average Swap Price per Bbl
Sep – Dec 2019	5,000	$ 64.54
	Oil (Midland Argus)	
Remaining Term	Bbl per Day	Weighted Average Price Differential

		per Bbl
Sep – Dec 2019	5,000	$ 10.37

Interest Rate Risk

At June 30, 2018, we had $73.0 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.

We are exposed to credit risk to the extent of nonperformance by Elk Petroleum with respect to the contingent payment derivative discussed above. Elk Petroleum is contractually obligated to pay Resolute the earned contingent payments pursuant to the purchase and sale agreement.

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 June 30, 2018. 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 June 30, 2018 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 June 30, 2018 does not materially differ from those set out in Part I, Item 1A of our Form 10-K.

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.

2018	Total Number of Shares Purchased(1)(2)	Average Price Paid Per Share
January 1 – 31	9,245	$ 31.47
February 1 – 28	1,101	$ 33.55
March 1 – 31	51,973	$ 34.36
April 1 – 30	—	$ —
May 1 – 31	—	$ —
June 1 – 30	—	$ —
Total	62,319	$ 33.92

(1) All shares purchased in 2018 were to offset tax withholding obligations that occur upon the vesting of outstanding restricted common shares under the terms of the Incentive Plan.

(2) As of June 30, 2018, the maximum number of shares that may yet be purchased would not exceed the employees' portion of taxes withheld on unvested shares (865,115 shares), outstanding stock options (707,876 options), shares available for issuance under the Incentive Plan (1,187,288 shares) and Outperformance Shares that may be earned in the future (315,101 shares).

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	Description
3.1	Second Amended and Restated Certificate of Incorporation of Resolute Energy Corporation dated June 19, 2018 (incorporated by reference to Exhibit 3.1 to the Form 8-K filed on June 19, 2018).
4.1	Supplemental Indenture, dated April 9, 2018, among Resolute Energy Corporation, the Guarantors and the Trustee, relating to the 8.50% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to the Form 8-K filed on April 10, 2018).
4.2	Registration Rights Agreement, dated April 9, 2018, among Resolute Energy Corporation, the Guarantors and the Purchasers, relating to the 8.50% Senior Notes due 2020 (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on April 10, 2018).
10.1	Settlement Agreement, dated May 15, 2018, by and among Resolute Energy Corporation, Monarch Energy Holdings LLC and Monarch Alternative Capital LP (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on May 16, 2018).
10.2	Purchase Agreement, dated April 5, 2018, among Resolute Energy Corporation, the Guarantors and the Purchasers, relating to the 8.50% Senior Notes due 2020 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on April 10, 2018).
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)	August 6, 2018
/s/ Theodore Gazulis Theodore Gazulis	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	August 6, 2018