Quarterly Report to Holders of 5.625% Senior Notes due 2025
For the quarterly period ended March 31, 2018

CrownRock, L.P.
18 Desta Drive
Midland, Texas 79705
(432) 818-0300

TABLE OF CONTENTS

Cautionary Statement Regarding Forward-Looking Statements

Certain statements and information in this report may constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). Such statements and information include projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "should," "would," "could," "may," "foresee," "plan," "goal" and "intend" and other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based forward-looking statements in this report on our current expectations and beliefs about future developments and their potential effect on us. While our management considers forward-looking statements contained in this report to be reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. Forward-looking statements contained in this report are inherently subject to significant business, economic, competitive, regulatory and other risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and present expectations or projections. Known material factors that could cause our actual results to differ from those implied by or expressed in forward-looking statements contained in this report are discussed in "Item 1A. Risk Factors," which include, but are not limited to:

- declines in the prices we receive for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- drilling and operating risks, including risks related to properties where we do not serve as the operator;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- risks related to the concentration of our operations in the Permian Basin of West Texas;
- potential financial losses or earnings reductions resulting from our commodity price risk management program;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- risks and liabilities associated with acquired properties, including the assets acquired in connection with each of our recent acquisitions and property exchanges;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- competition in the oil and natural gas industry; and
- our substantial existing indebtedness.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. We disclaim any obligation to update or revise any forward-looking statements contained in this report unless required by securities law.

CROWNROCK, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

		March 31, 2018		December 31, 2017
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$	53,109	$	96,067
Accounts receivable – related party:				
Oil and natural gas		53,463		42,682
Other		3,958		769
Prepaid costs and other current assets		3,692		4,928
Derivative instruments		43,961		59,044
Total current assets		158,183		203,490
Oil and natural gas properties, net, successful efforts method of accounting		1,766,577		1,655,176
Other property and equipment, net		94,395		93,409
Deferred loan costs, net		2,245		2,519
Noncurrent derivative instruments		13,426		-
Other assets		8,036		6,267
Total Assets	$	2,042,862	$	1,960,861
LIABILITIES AND PARTNERS' CAPITAL				
Current liabilities:				
Accounts payable – related party	$	-	$	97
Accrued drilling cost – related party		16,390		968
Other accrued liabilities – related party		8,047		6,060
Accrued interest payable		26,563		12,500
Current portion of long-term debt		1,005		993
Other current liabilities		578		765
Asset retirement obligations, current portion		262		159
Total current liabilities		52,845		21,542
Long-term debt, net		997,143		997,005
Noncurrent derivative instruments		-		1,241
Asset retirement obligations		20,700		20,072
Other noncurrent liabilities		-		555
Total liabilities		1,070,688		1,040,415
Commitments and Contingencies (Note J)				
CrownRock, L.P. Partners' Capital		971,749		919,991
Non-controlling interest in subsidiary		425		455
Total Partners' Capital		972,174		920,446
Total Liabilities and Partners' Capital	$	2,042,862	$	1,960,861

See accompanying notes to these unaudited consolidated financial statements.

CROWNROCK, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
	(In thousands)	
Statements of Income		
Revenues and gains:		
Oil and natural gas sales	$ 137,423	$ 68,971
Gain on sales and exchanges of oil and natural gas properties	-	5,354
Rental income - gathering system	477	337
Transportation fees and saltwater disposal income	3,084	703
Surface ownership income	334	-
Fresh water supply income	982	-
Total revenues and gains	142,300	75,365
Costs and expenses:		
Lease operating expense	20,624	15,458
Production and ad valorem taxes	8,071	4,844
Exploration costs	5	3,072
Depreciation, depletion and amortization	44,328	30,840
Impairment of oil and natural gas properties and facilities	645	1,988
Accretion of discount on asset retirement obligation	230	199
General and administrative	5,742	4,953
Total costs and expenses	79,645	61,354
Operating income	62,655	14,011
Other income (expense):		
Gain on derivatives not designated as hedges	8,550	31,476
Interest income	83	-
Interest expense	(15,484)	(15,642)
Other income (expense), net	11	(108)
Total other income (expense)	(6,840)	15,726
Net income	55,815	29,737
Net loss attributable to non-controlling interest	30	25
Net income attributable to CrownRock, L.P.	$ 55,845	$ 29,762
Statements of Comprehensive Income		
Net income	$ 55,815	$ 29,737
Less: Comprehensive loss attributable to the non-controlling interest	30	25
Comprehensive income attributable to CrownRock, L.P.	$ 55,845	$ 29,762

See accompanying notes to these unaudited consolidated financial statements.

CROWNROCK, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(Unaudited)

	Limited Partner		Class A		Class B		Class C		Class D		Class E		Treasury Units		Total CrownRock, LP Partners' Capital	Non-Controlling Interest	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount			
(In thousands, except units)																	
Balance, January 1, 2017	-	$ -	8,848,300	$ 657,578	1,500,000	$ 109,207	1,500,000	$ 196,653	490,500	$ 12,218	-	$ -	79,837	$ (13,538)	$ 962,118	$ 566	$ 962,684
Net loss	-	-	-	(29,395)	-	(4,983)	-	(8,594)	-	-	-	-	-	-	(42,972)	(111)	(43,083)
Distributions to partners	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Unit-based compensation	-	-	-	-	-	-	-	-	6,000	3,879	5,500	43	-	-	3,922	-	3,922
Purchase of treasury units:																	
Class A units	-	-	-	-	-	-	-	-	-	-	-	-	1,004	(249)	(249)	-	(249)
Class B units	-	-	-	-	-	-	-	-	-	-	-	-	1,110	(275)	(275)	-	(275)
Class C units	-	-	-	-	-	-	-	-	-	-	-	-	1,110	(475)	(475)	-	(475)
Class D units	-	-	-	-	-	-	-	-	-	-	-	-	3,612	(2,078)	(2,078)	-	(2,078)
Class D and E unit forfeitures	-	-	-	-	-	-	-	-	(6,100)	-	(500)	-	-	-	-	-	-
Balance, December 31, 2017	-	$ -	8,848,300	$ 628,183	1,500,000	$ 104,224	1,500,000	$ 188,059	490,400	$ 16,097	5,000	$ 43	86,673	$ (16,615)	$ 919,991	$ 455	$ 920,446
Units canceled upon merger transaction	-	-	(8,848,300)	(628,183)	(1,500,000)	(104,224)	(1,500,000)	(188,059)	(490,400)	(16,097)	(5,000)	(43)	(86,673)	16,615	(919,991)	-	(919,991)
Units issued to CrownRock Holdings upon merger transactions	100	919,991	-	-	-	-	-	-	-	-	-	-	-	-	919,991	-	919,991
Net income (loss)	-	55,845	-	-	-	-	-	-	-	-	-	-	-	-	55,845	(30)	55,815
Distribution to limited partner	-	(5,171)	-	-	-	-	-	-	-	-	-	-	-	-	(5,171)	-	(5,171)
Capital contribution - unit based compensation	-	1,084	-	-	-	-	-	-	-	-	-	-	-	-	1,084	-	1,084
Balance, March 31, 2018	100	$ 971,749	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	$ 971,749	$ 425	$ 972,174

See accompanying notes to these unaudited consolidated financial statements.

CROWNROCK, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31, 2018	2017
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 55,815	$ 29,737
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	44,328	30,840
Accretion of discount on asset retirement obligation	230	199
Accretion of discount on long-term debt	-	134
Amortization of deferred loan costs	668	748
Unit-based compensation expense	1,084	975
Exploration costs	5	3,072
Settlements of asset retirement obligations	(10)	(11)
Impairment of oil and natural gas properties and facilities	645	1,988
(Gain) loss on derivative instruments	416	(4,720)
Gain on sales and exchanges of oil and natural gas properties	-	(5,354)
Loss on equity method investments	13	-
Change in assets and liabilities:		
Accounts receivable – related party	(13,969)	319
Prepaid costs and other current assets	1,236	1,202
Accounts payable - related party	(97)	-
Other accrued liabilities - related party	(2,974)	(3,164)
Accrued interest payable	14,063	433
Other liabilities	(750)	(555)
Net cash flows provided by operating activities	100,703	55,843
Cash flows from investing activities:		
Acquisition of leasehold and oil and natural gas properties	(1,633)	(5,097)
Capital expenditures on oil and natural gas properties	(138,102)	(76,794)
Additions to other property and equipment	(1,688)	(2,527)
Proceeds from sales and exchanges of oil and natural gas properties	-	7,247
Contributions to equity method investments	(1,782)	-
Net cash flows used in investing activities	(143,205)	(77,171)
Cash flows from financing activities:		
Repayments of long-term borrowings under construction loan	(245)	(234)
Payments for loan and debt issue costs	(182)	9
Purchase of treasury units	(29)	(4,920)
Net cash flows used in financing activities	(456)	(5,145)
Net decrease in cash and cash equivalents	(42,958)	(26,473)
Cash and cash equivalents, beginning of period	96,067	123,779
Cash and cash equivalents, end of period	$ 53,109	$ 97,306
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 753	$ 14,327
Non-cash investing and financing activities:		
Change in accrued capital expenditures in accrued drilling cost and accrued liabilities	$ 15,422	$ (1,711)
Additions to asset retirement obligation	511	316
Asset retirement obligation associated with properties exchanged or sold	-	(628)
Accrued loan origination costs	182	-
Accrued distribution to limited partner	5,171	-
Change in accrued treasury unit purchase	(29)	(4,920)

See accompanying notes to these unaudited consolidated financial statements.

CROWNROCK, L.P.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

A. Organization and Nature of Operations

CrownRock, L.P. ("the Partnership") is a Delaware limited partnership formed on February 14, 2007 by affiliates of CrownQuest Operating, LLC ("CrownQuest"), an independent oil and natural gas producer who is a wholly-owned subsidiary of one of the members of the Partnership's ultimate general partner, and Lime Rock Partners, a private equity firm focused on the oil and natural gas industry ("Lime Rock"). The Partnership's principal business is the acquisition, development, exploration and production of oil and natural gas properties primarily located in the Permian Basin of West Texas.

On December 21, 2017, affiliates of CrownQuest's management team and Lime Rock formed CrownRock Holdings, L.P., a Delaware limited partnership ("Holdings"). Effective January 1, 2018, the Partnership merged with a subsidiary of Holdings, and, as a result, Holdings is now the sole limited partner and holder of 100% of the Partnership's limited partnership interests. The Partnership admitted Holdings as its sole limited partner by issuing 100 new limited partnership units and cancelling all its other limited partner interests comprised of Class A, B, C, D and E limited partnership units. Holdings issued equivalent units of equivalent classes to the former limited partners of the Partnership. As the ownership of the Partnership was identical prior to and after the merger, it was considered a transaction between entities under common control.

B. Summary of Significant Accounting Policies

Organization and principles of consolidation. The Partnership is the sole member of Roddy Production Company, LLC ("Roddy") and a 51% owner of Abajo Gas Transmission Company, LLC ("Abajo"). The consolidated financial statements include the accounts of the Partnership and its majority-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

On July 7, 2011, CrownRock Finance, Inc. ("CrownRock Finance"), a Delaware corporation and wholly-owned subsidiary of the Partnership, was organized for the sole purpose of serving as co-issuer of senior notes and it is currently a co-issuer of $1 billion of senior notes due October 15, 2025. CrownRock Finance currently has, and will have, no operations, assets or liabilities other than with respect to the notes or other debt securities the Partnership may issue in the future. See Note O – Supplemental Guarantor Information and Note M – Long-term debt.

On February 28, 2014, Canvasback Properties, LLC ("Canvasback"), a Texas corporation and wholly-owned subsidiary of the Partnership, was organized for the purpose of constructing, owning and managing an office building in Midland, Texas, which is the Partnership's headquarters, and a field operations office in Martin County, Texas.

Interim financial statements. These consolidated financial statements as of March 31, 2018 and for the three months ended March 31, 2018 and 2017 are unaudited. In the opinion of management, such financial statements include the adjustments and accruals, all of which are of a normal recurring nature, which are necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results for a full year. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission. These unaudited consolidated financial statements should be read in conjunction with the Partnership's annual financial statements for the year ended December 31, 2017.

Cash and cash equivalents. The Partnership considers all highly liquid instruments with original maturities of three months or less to be cash equivalents.

B. Summary of Significant Accounting Policies (Continued)

Accounts receivable and allowance for doubtful accounts. CrownQuest markets the Partnership's oil and natural gas to various customers. Oil and natural gas sales receivables are generally unsecured. CrownQuest monitors exposure to these customers primarily by reviewing credit ratings, financial statements and payment history. CrownQuest extends credit terms based on their evaluation of each customer's creditworthiness. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Partnership does not have any off balance sheet credit exposure related to its customers.

Oil and natural gas properties. The Partnership uses the successful efforts method of accounting for its investments in oil and natural gas properties. Under such method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized.

Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. If the unproved properties are determined to be productive, the related costs are transferred to proved oil and natural gas properties.

Capitalized costs of producing oil and natural gas properties, net of estimated salvage values, are depreciated and depleted by the units-of-production method. Acquisition and leasehold costs of proved properties are amortized on the basis of total proved reserves, and capitalized development costs (wells and related equipment and facilities) are amortized on the basis of proved developed reserves.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resulting gain or loss is recognized. On the sale or retirement of a partial unit of proved property, the costs, net of proceeds, are charged to accumulated depreciation, depletion, and amortization, unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized in the statement of operations. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of costs without recognizing any gain or loss. See Note N – Exchanges for additional information.

On exchanges of oil and natural gas assets with third parties, the Partnership reviews the transactions for certain key aspects that may have a significant impact on its accounting. Exchange transactions that only involve unproved properties are generally measured on recorded values rather than fair values. Thus, no gain or loss is recognized. Conversely, exchange transactions involving proved developed properties must be analyzed for possible business combinations and commercial substance. These aspects, along with others, dictate whether the Partnership records exchanges at recorded values or fair values and whether gains or losses should be recognized.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. The Partnership reviews its oil and natural gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. The Partnership assesses impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. Estimating future cash flows involves the use of judgments, including estimation of the proved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. Unproved properties are assessed for impairment at least annually on a property-by-property basis, and any impairment is charged to expense. If the unproved properties are determined to be productive, the related costs are transferred to proved oil and natural gas properties.

B. Summary of Significant Accounting Policies (Continued)

The Partnership periodically reviews its proved and unproved oil and natural gas properties that are sensitive to oil and natural gas prices for impairment. Impairment expense is caused primarily due to declines in commodity prices and well performance.

The leasehold acreage quantity information disclosed throughout these consolidated financial statements is unaudited.

Deferred loan costs. Costs incurred in connection with the issuance of debt are deferred and recorded on the balance sheet. Costs associated with the bank credit facility are included in noncurrent assets; costs associated with the senior notes and the Canvasback construction loan are included as direct deductions from the carrying amounts of the debt liabilities. Deferred loan costs are stated net of amortization, which is computed using the straight-line method and approximates the effective interest method. The debt issue costs are amortized to interest expense over the life of the debt.

Future amortization expense of deferred loan costs at March 31, 2018 was as follows:

In thousands		
Remaining 2018	$	2,009
2019		2,679
2020		1,900
2021		1,579
2022		1,579
Thereafter		4,404
Total	$	14,150

Equity method investment. In August 2017, the Partnership executed a Limited Liability Company Agreement in which it became a voting equity member of a newly-formed oil and natural gas service company, Silvertip Completion Services, LLC ("Silvertip"), that provides wireline and pump down services to exploration and production companies operating in the Permian Basin. In exchange for the equity units in the service company, through March 31, 2018, the Partnership has contributed $8.7 million in cash (including $1.8 million during the three months ended March 31, 2018) and committed up to an additional $5.3 million payable upon the Partnership receiving capital calls from Silvertip. The Partnership's capital commitment to Silvertip expires on August 31, 2020. The Partnership currently owns approximately 35% of all outstanding voting equity units and is accounting for the investment utilizing the equity method of accounting. The Partnership's investment in Silvertip is included in other assets on the balance sheet. During the three months ended March 31, 2018, CrownRock recognized a $13,000 loss associated with its share of the net loss of Silvertip for the quarter. All intra-entity income and losses have been eliminated.

Use of estimates. Preparing financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The financial statements are based on a number of significant estimates including oil and natural gas reserve quantities and values, which are the basis for oil and natural gas properties acquired or exchanged, calculation of depletion, depreciation and amortization, asset retirement obligations, and impairment of oil and natural gas properties.

Fair value. Fair value is defined as the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

B. Summary of Significant Accounting Policies (Continued)

Level 1. Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Partnership considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2. Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Partnership values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Instruments in this category are non-exchange traded derivatives such as over-the-counter commodity price swaps. The Partnership's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Partnership utilizes its counterparties' valuations to assess the reasonableness of its prices and valuation techniques.

Level 3. Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e. supported by little or no market activity). Items included in this category are asset retirement obligations, asset impairments and asset acquisitions and exchanges.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Partnership's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Unit-based compensation. From time to time, Holdings exchanges its equity instruments for services provided by the officers and employees of CrownQuest that are based on the fair value of Holdings' equity instruments or that may be settled by the issuance of those equity instruments in exchange for the services. The cost of the services received in exchange for equity instruments is measured based on the grant-date fair value of those instruments. The compensation costs associated with the services provided is treated as a deemed capital contribution from Holdings to the Partnership. That cost is recognized by the Partnership as compensation expense over the requisite service period (generally the vesting period).

Recent accounting pronouncements. In January 2017, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business," with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired is concentrated in a single asset or a group of similar assets, the set is not a business. This new guidance is effective for the Partnership for annual periods beginning after December 15, 2018, and early adoption is allowed. The Partnership is currently evaluating the impact of ASU No. 2017-01 on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). The new standard establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new standard is effective for the Partnership for fiscal periods beginning after December 15, 2019, including interim periods within those fiscal periods. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Partnership is currently evaluating the impact of the pending adoption of ASU No. 2016-02 on its consolidated financial statements.

B. Summary of Significant Accounting Policies (Continued)

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers", which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP. The implementation of this standard is to be done using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosure). Early application of the guidance in this ASU is permitted with certain restrictions.

In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers", which deferred the original effective dates of ASU 2014-09 for the Partnership to annual periods beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2019. The Partnership has formed an internal task force to evaluate the impact of its pending adoption of ASU 2014-09 on its consolidated financial statements. The task force is currently gathering general and upstream oil and gas industry-specific information and has begun compiling information about the Partnership's existing contracts with customers, but has not yet determined the method by which it will adopt the standard in 2019.

Subsequent events. The Partnership performed an evaluation of subsequent events through May 10, 2018, which is the date the consolidated financial statements were available to be issued.

C. Oil and Natural Gas Properties

The following table sets forth information concerning the Partnership's oil and natural gas properties as of March 31, 2018 and December 31, 2017:

	March 31, 2018	December 31, 2017
	(In thousands)	
Proved oil and natural gas properties	$ 2,189,517	$ 2,053,382
Unproved oil and natural gas properties	229,579	211,637
Less accumulated depreciation, depletion, amortization and impairment	(652,519)	(609,843)
Net oil and natural gas properties	$ 1,766,577	$ 1,655,176

During the three months ended March 31, 2018, the Partnership recognized exploration costs of approximately $5 thousand related to geological and geophysical costs. During the three months ended March 31, 2017, the Partnership recognized exploration costs of approximately $3.1 million comprised of approximately $2.8 million of expired oil and natural gas leases in the Permian Basin of Texas, which were determined to have no future development potential.

During the three months ended March 31, 2018, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of approximately $0.6 million to provide as estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire. During the three months ended March 31, 2017, the Partnership recognized a non-cash charge against earnings of approximately $1.2 million of producing oil and natural gas properties in the Permian Basin of New Mexico. Additionally, during the three months ended March 31, 2017, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of $0.8 million to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire.

C. Oil and Natural Gas Properties (Continued)

See Note I – Fair Value for discussion of proved property impairments recorded during the three months ended March 31, 2017. No proved property impairments were recorded during the three months ended March 31, 2018.

The Partnership initiated a horizontal well drilling program in January 2015. The Partnership capitalizes exploratory horizontal and vertical well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory horizontal well costs included in unproved oil and natural gas properties pending the determination of proved reserves at March 31, 2018 were $3.7 million. All of these costs are from wells drilled during the three months ended March 31, 2018.

D. Other Property and Equipment

The following table sets forth the Partnership's other property and equipment as of March 31, 2018 and December 31, 2017:

	March 31, 2018	December 31, 2017
	(In thousands)	
Land	$ 24,091	$ 23,000
Water rights	11,872	11,872
Construction in progress - office building	-	1,620
Construction in progress - gathering systems	1,211	1,211
Office buildings	26,021	23,808
Equipment	56	56
Gathering systems	37,625	37,612
Pipeline and gathering facilities	11,714	11,714
Less accumulated depreciation and impairment	(18,195)	(17,484)
Net other property and equipment	$ 94,395	$ 93,409

Land and water rights. On September 13, 2017, the Partnership acquired 4,960 net surface acres of land located in Howard and Martin counties, Texas from a third party for $20.8 million in cash. The surface acreage is located in a portion of the Partnership's core northern Midland Basin leasehold acreage. The Partnership's purchase of the surface acreage is part of its ongoing strategy to cost-effectively support its horizontal drilling program in the Midland Basin. The Partnership also acquired the water rights attached to the surface acreage. The acquisition of these water rights will allow the Partnership to drill water wells and construct water storage facilities on the surface that will support the drilling and completion of its future horizontal oil and natural gas wells on or in close proximity to the surface acreage. The Partnership accounted for this transaction as an asset acquisition and allocated the purchase price based on relative fair values of the assets acquired. The Partnership allocated the purchase price of this acquisition to land ($7.3 million); water rights ($11.8 million); and unproved leasehold costs ($1.7 million).

Office buildings. Canvasback owns a 60,800 square feet office building in Midland, Texas which is the Partnership's headquarters. Canvasback also owns a 30,250 square feet building in Martin County, Texas which is the Partnership's field operations headquarters.

In June 2017, Canvasback commenced construction of a 15,140 square feet extension of the Partnership's field operations headquarters building in Martin County, Texas. The office building was completed in February 2018.

D. Other Property and Equipment (Continued)

Gathering systems. The Partnership owns a low-pressure gas gathering system that covers approximately 110 square miles in western Howard and northern Glasscock Counties, Texas. It is designed to gather up to 50,000 Mcf per day of casinghead gas from CrownQuest operated and non-operated oil and natural gas wells in close proximity. It consists of approximately 125 linear miles of high-density polyethylene pipe and connects to a large midstream company's gathering system at three compressor sites.

The Partnership owns a gas, oil, and produced water gathering system that covers approximately 25 square miles in Midland County, Texas. The gas gathering system is designed to gather up to 50,000 Mcf per day of casinghead gas from CrownQuest operated wells near its proximity, while the oil and produced water gathering systems, which parallel the gas system, are designed to gather a combined 50,000 barrels per day of produced liquids. The three systems contain approximately 125 linear miles of high-density polyethylene pipe and connect CrownQuest operated leases to a large midstream company's gas pipeline, oil purchasers, and salt water disposal systems in the area.

E. Asset Retirement Obligations

The Partnership records a liability for the present value of all legal obligations associated with the retirement of tangible long-lived assets and capitalizes an equal amount as part of the cost of their related oil and natural gas properties. Asset retirement obligations are initially recorded at fair value and assessed for revisions periodically thereafter. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs and well life. The inputs are calculated based on historical data as well as current estimated costs.

The following table summarizes the changes in the Partnership's asset retirement obligation during the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Balance, beginning of period	$ 20,231	$ 18,677
Liabilities incurred during the period	511	316
Liabilities settled during the period	(10)	(11)
Liabilities associated with properties exchanged	-	(628)
Accretion expense	230	199
Balance, end of period	20,962	18,553
Less current portion	(262)	(854)
Non-current portion	$ 20,700	$ 17,699

Asset retirement obligations for natural gas pipeline facilities generally become firm at the time the facilities are permanently shut down and dismantled. These obligations may include the costs of asset disposal and additional soil remediation. However, these sites have indeterminate lives based on plans for continued operations and as such, the fair value of the conditional legal obligations cannot be measured since it is impossible to estimate the future settlement dates of such obligations.

F. Credit and Counterparty Risk

Cash and cash equivalents are maintained at financial institutions and, at times, balances may exceed federally insured limits. Amounts on deposit in excess of federally insured limits at March 31, 2018 approximated $51.7 million. The Partnership treats all investment securities with original maturities of 90 days or less as cash equivalents.

F. Credit and Counterparty Risk (Continued)

At March 31, 2018, the Partnership has a derivative asset of $57.4 million which is subject to its counterparties' credit and performance risk. The Partnership routinely monitors the creditworthiness of its counterparties, but does not require collateral or other security to support derivative instruments. However, agreements with the counterparties contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under derivative contracts with the amount due from the defaulting party under derivative contracts. As a result of the netting provisions, the Partnership's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparty under the derivative contracts.

G. Related Party Transactions

Related party operator of oil and natural gas properties. Most of the Partnership's properties are operated by CrownQuest. As of March 31, 2018, and December 31, 2017, aggregate related party accounts payable and accrued liabilities owed to CrownQuest in the normal course of the Partnership's oil and natural gas property operations were $24.4 million and $7.1 million, respectively, related specifically to accrued drilling costs on wells being drilled and completed as of period end, accrued lease operating expenses, accrued distribution payable and accrued management fees. Further, with respect to the properties operated by CrownQuest, at March 31, 2018 and December 31, 2017, related party accounts receivable outstanding in the normal course of business related primarily to accrued oil and natural gas sales were $57.4 million and $43.5 million, respectively.

Management fees paid to related party. Pursuant to an administrative agreement, the Partnership pays CrownQuest a monthly management fee based upon an annual budget approved by the Partnership. The Partnership is required to reimburse CrownQuest for substantially all costs, which include employee expense, rent expense, license fees, insurance cost, general office expenses, depreciation expense related to capitalized equipment, third party charges incurred for the benefit of the Partnership, and any and all expenses incurred by CrownQuest in providing support to the Partnership net of any amounts received under any operating agreements. For the three months ended March 31, 2018 and 2017, the Partnership recorded management fees of $4.7 million and $3.9 million, respectively, in general and administrative expenses.

Royalty and other payments to affiliates. CrownQuest, as the operator of the Partnership's properties, periodically makes various types of payments to companies affiliated with CrownQuest. During the three months ended March 31, 2018 and 2017, payments of $6.6 million and $3.2 million, respectively, were made by the operator to affiliates for royalty interests, lease bonuses and extensions, surface acquisitions, surface damages and water purchases with respect to such properties. Payments for the three months ended March 31, 2018 and 2017, include amounts paid to a CrownQuest-affiliated royalty company formed in March 2016. Payments to this royalty company for the three months ended March 31, 2018 were $3.0 million for royalty interests. Payments to this royalty company for the three months ended March 31, 2017 were $1.8 million primarily for royalty interests.

CrownQuest payments to CrownRock. As a result of its ownership of surface acreage, water rights and infrastructure, the Partnership periodically receives payments from CrownQuest for surface damages, fresh water purchases and water disposal. During the three months ended March 31, 2018, CrownQuest paid the Partnership $1.4 million for these transactions. There were no transactions of these types during the three months ended March 31, 2017.

Oil and natural gas property lease from an officer of CrownQuest. A family partnership controlled by Mr. Robert W. Floyd, President of CrownQuest and Director of the Partnership's general partner, CrownRock GP, LLC, and his wife has royalty interests in certain properties that the Partnership is developing in the Permian Basin. For the three months ended March 31, 2018 and 2017, the Partnership paid $2 thousand each year for royalty interests.

G. Related Party Transactions (Continued)

In a series of transactions beginning in August 2013, the Partnership entered into oil and natural gas property lease agreements with several relatives of Mr. Floyd and a family limited liability company in which Mr. Floyd owns a 33 1/3% interest. The leases are for unproved acreage in the Midland Basin in West Texas. The Partnership is currently developing this acreage. During the three months ended March 31, 2018 and 2017, the Partnership paid $1.0 million and $0.7 million, respectively, for royalty interests and lease bonuses.

In June 2014, the Partnership entered into an oil and natural gas property lease agreement with a relative of Mr. Floyd for unproved acreage in the Midland Basin in West Texas. The Partnership is currently developing this acreage. The Partnership agreed to pay Mr. Floyd's relative an aggregate of $2.78 million. As of March 31, 2018, the remaining obligation is $555,000 which is included in other current liabilities in the consolidated balance sheet. Such amount will be paid in January 2019.

Related party owner and operator of aircraft used by CrownQuest. During 2012, Mr. Floyd and EnerQuest Oil & Gas Ltd. ("EOG"), an entity affiliated with the Partnership, formed an entity named EnerQuest Aviation Partners, LLC ("Aviation Partners") and acquired 50% of an aircraft with the other 50% belonging to a third party individual. The aircraft is managed by Crown Eye Partners, LLC ("Crown Eye") which is owned 50% by Aviation Partners and 50% by the same third party individual. This aircraft is available for use by CrownQuest employees when conducting business on behalf of the Partnership. The Partnership pays CrownQuest's usage of the aircraft under the terms of the administrative support agreement. During the three months ended March 31, 2018, CrownQuest paid Crown Eye $17.1 thousand for usage of the aircraft for 8.1 hours at an average cost of $2,120 per hour. During the three months ended March 31, 2017, CrownQuest paid Crown Eye $55 thousand for usage of the aircraft for 27.0 hours at an average cost of $2,031 per hour.

Equity investment provider of oilfield services to CrownQuest. Silvertip provides wireline and pump down services to companies operating in the Permian Basin, including CrownQuest. CrownQuest procures these services for wells in which the Partnership has working interests. During the three months ended March 31, 2018, Silvertip billed CrownQuest $1.7 million for services provided on Partnership-owned properties. The Partnership has eliminated all intra-entity income and losses related to these services. Silvertip did not provide any services to CrownQuest during the three months ended March 31, 2017.

H. Derivative Financial Instruments

The Partnership has entered into derivative contracts with counterparties that are lenders under its revolving credit facility to manage its exposure to commodity price fluctuations associated with a portion of the Partnership's oil and natural gas production.

The Partnership does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Partnership records all derivative instruments on the consolidated balance sheets at fair value. The Partnership nets derivative assets and liabilities for counterparties where the Partnership has a legal right of offset. Further, the Partnership reflects changes in the fair value of its derivative instruments currently in its consolidated statements of operations as they occur.

H. Derivative Financial Instruments (Continued)

Commodity derivative contracts at March 31, 2018. The following table sets forth the Partnership's outstanding commodity derivative contracts, by quarter of settlement, at March 31, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2018:					
Volume (Bbl)		1,783,600	2,033,200	2,162,000	5,978,800
Price per Bbl		$ 67.84	$ 68.78	$ 67.81	$ 68.15
2019:					
Volume (Bbl)	1,152,000	-	-	-	1,152,000
Price per Bbl	$ 60.45	$ -	$ -	$ -	$ 60.45
Oil Basis Swaps: (b)					
2018:					
Volume (Bbl)		819,000	552,000	552,000	1,923,000
Price per Bbl		$ 0.07	$ -	$ -	$ 0.03
2019:					
Volume (Bbl)	1,890,000	2,275,000	2,300,000	2,300,000	8,765,000
Price per Bbl	$ (0.35)	$ (0.35)	$ (0.35)	$ (0.35)	$ (0.35)
2020:					
Volume (Bbl)	1,092,000	1,092,000	1,104,000	1,104,000	4,392,000
Price per Bbl	$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)

(a) The index prices for the oil price swaps are based on the NYMEX - West Texas Intermediate monthly average futures price.
(b) The basis differential price is between Midland - WTI and Cushing - WTI.

The following table summarizes the activity in the Partnership's derivative instruments, for each of the periods indicated:

	Three Months Ended March 31,		Year Ended December 31,
	2018	2017	2017
	(In thousands)		(In thousands)
Net asset, beginning of period	$ 57,803	$ 157,049	$ 157,049
Cash settlement receipts	(8,966)	(26,756)	(108,266)
Changes in fair value of derivatives	8,550	31,476	9,020
Net asset end of period	57,387	161,769	57,803
Less current asset	43,961	98,787	59,044
Non-current asset (liability)	$ 13,426	$ 62,982	$ (1,241)

H. Derivative Financial Instruments (Continued)

Our commodity derivatives are presented on a net basis in "derivative instruments" on the Condensed Consolidated Balance Sheets. The following table summarizes the gross fair values of our derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on our Condensed Consolidated Balance Sheets for the periods indicated (in thousands):

	Three Months Ended March 31, 2018		
	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Derivatives not designated as hedging instruments			
Asset Derivatives:			
Commodity price derivatives	$ 70,921	$ (13,534)	$ 57,387
Liability Derivatives:			
Commodity price derivatives	$ (13,534)	$ 13,534	$ -

	Year Ended December 31, 2017		
	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Derivatives not designated as hedging instruments			
Asset Derivatives:			
Commodity price derivatives	$ 67,747	$ (8,703)	$ 59,044
Liability Derivatives:			
Commodity price derivatives	$ (9,944)	$ 8,703	$ (1,241)

I. Fair Value

Assets and Liabilities Measured at Fair Value on a Recurring Basis. The following table sets forth by level within the fair value hierarchy the Partnership's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2018 and December 31, 2017:

	Fair value measurements using			
Description	**Quoted prices in active markets (Level 1)**	**Other observable inputs (Level 2)**	**Unobservable inputs (Level 3)**	**Fair Value**
		(In thousands)		
Oil and oil basis swaps	$ -	$ 57,387	$ -	$ 57,387
Total as of March 31, 2018	$ -	$ 57,387	$ -	$ 57,387
Oil and oil basis swaps	$ -	$ 57,803	$ -	$ 57,803
Total as of December 31, 2017	$ -	$ 57,803	$ -	$ 57,803

I. Fair Value (Continued)

The Partnership estimates the fair values of the swaps based on published forward commodity price curves for the underlying commodities as of the date of the estimate for those commodities for which published forward pricing is readily available. For those commodity derivatives for which forward commodity price curves are not readily available, the Partnership estimates, with the assistance of third-party pricing experts, the forward curves as of the date of the estimate. Using a discounted cash flow model, the determination of the fair values above incorporates various factors including the impact of the Partnership's non-performance risk, the credit standing of the counterparties involved in the Partnership's derivative contracts, NYMEX future prices and interest rates.

The following table represents the carrying amounts and fair values of the Partnership's financial instruments at March 31, 2018 and December 31, 2017:

	March 31, 2018		December 31, 2017	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Assets:				
Derivative instruments	$ 57,387	$ 57,387	$ 59,044	$ 59,044
Liabilities:				
Derivative instruments	$ -	$ -	$ (1,241)	$ (1,241)

Cash and cash equivalents, accounts receivable, accounts payable and interest payable. The carrying amounts approximate fair value due to the short maturity of these instruments.

Credit facility. The fair value of the revolving credit facility borrowings approximate the carrying amounts based upon interest rates currently available to the Partnership for borrowings with similar terms (Level 2).

Senior notes. The fair value of the Partnership's 5.625% Senior Notes due 2025 was $988.8 million at March 31, 2018. Such fair value was determined using Level 2 inputs including quoted period end market prices.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. Non-recurring fair value measurements include certain nonfinancial assets and liabilities as may be acquired in a business combination or property exchange and thereby measured at fair value; impaired oil and natural gas property assessments; unit-based compensation; and the initial recognition of asset retirement obligations for which fair value is used. These estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Partnership has designated these estimates as Level 3.

Impairments of long-lived assets. The Partnership periodically reviews for impairment its long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. During the three months ended March 31, 2018, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of $0.6 million to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire. During the three months ended March 31, 2017, the Partnership recognized a non-cash charge against earnings of approximately $1.2 million of producing oil and natural gas properties in the Permian Basin of New Mexico. Additionally, during the three months ended March 31, 2017, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of $0.8 million to provide an estimated allowance related to unproved oil and natural gas leases which expired in the second quarter of 2017 and which the Partnership did not have any specific plans to develop.

Unit-based compensation. See fair value disclosures in Footnote L – Incentive Plans.

J. Commitments and Contingencies

As part of the administrative agreement between the Partnership and CrownQuest, the Partnership reimburses CrownQuest for rent expense. At March 31, 2018, CrownQuest was party to three operating leases for office space:

(a) Lease agreement dated June 19, 2014 with Canvasback as lessor on the 59,134 square feet headquarters office in Midland County, Texas. The lease agreement was effective December 1, 2015 and terminates on June 30, 2026.
(b) Lease agreement dated October 8, 2015 with Canvasback as lessor on the 30,250 square feet field operations office and 4,000 square feet barn in Martin County, Texas. The lease agreement was effective September 1, 2015 and terminates on September 1, 2020.
(c) Lease agreement dated April 18, 2018 with Canvasback as lessor on the 15,140 square feet extension of the field operations office in Martin County, Texas. The lease agreement was effective February 1, 2018 and terminates on September 1, 2020.

For the three months ended March 31, 2018 and 2017, the Partnership reimbursed CrownQuest for rent expense for office space of $568 thousand and $535 thousand, respectively, included in the monthly management fee. The rent expense relates to the Canvasback leases which are eliminated in consolidation.

CrownQuest has entered into contracts to secure the availability of drilling rigs and are subject to payments in accordance with the contracts based on the utilization of the drilling rigs.

From time to time, the Partnership is party to ordinary routine litigation incidental to the business. The Partnership believes that the results of such proceedings will not have a material adverse effect on its consolidated financial statements

K. Partners' Capital

CrownRock, L.P. is a privately held limited partnership formed in the State of Delaware on February 14, 2007. The ultimate general partner (as defined below) has the exclusive right to manage the business of the Partnership and has all powers and rights necessary or advisable to effectuate and carry out the purposes and business of the Partnership.

Effective January 1, 2018, the Partnership merged with a subsidiary of Holdings. As a result of this merger, the Partnership and its general partner became wholly-owned subsidiaries of Holdings. The Partnership admitted Holdings as its sole limited partner by issuing 100 new limited partnership units and cancelling all its other limited partner interests comprised of Class A, B, C, D and E limited partnership units. Holdings issued equivalent units of equivalent classes to the former limited partners of the Partnership. The only outstanding units of the Partnership at March 31, 2018 are the 100 limited partnership units held by Holdings. Additionally, effective January 1, 2018, the Partnership executed the Second Amended and Restated Limited Partnership Agreement to provide for sole control and management of the Partnership by the general partner and the simplification of the governance of the Partnership.

K. Partners' Capital (Continued)

After January 1, 2018, distributions will be made solely to Holdings as the Partnership's sole limited partner. On January 4, 2018, Holdings issued 475,000 Series A Preferred units to investors for a purchase price of $1,000 per unit. Holdings must make quarterly tax distributions in cash to the holders of its Series A Preferred Units in cash beginning with the quarter ending March 31, 2018. The amount of such tax distributions for 2018 is expected to be approximately $22.5 million. Since Holdings' only asset is its ownership of the Partnership and the Partnership's general partner, the funds Holdings requires to pay the quarterly tax distributions will be obtained from the Partnership paying quarterly distributions to Holdings. To provide Holdings with funds required to make its quarterly tax distribution, the Partnership distributed $5.2 million to Holdings on April 13, 2018. The Partnership's credit facility and the indenture governing its 2025 Senior Notes have restrictive covenants limiting dividends and distributions (See Note M – Long-term Debt). The Partnership estimates that it can pay the necessary quarterly tax distributions to Holdings within the limits of these two agreements.

Based upon the provisions of the indenture governing the Partnership's senior notes, as of March 31, 2018, the Partnership is allowed to make distributions to Holdings of approximately $211.1 million.

L. Incentive Plans

Defined contribution plan. CrownQuest sponsors a 401(k) defined contribution plan for the benefit of substantially all employees. Currently, CrownQuest matches 100% of employee contributions, not to exceed 5% of the employee's annual salary. The Partnership's contributions to the plan, through its reimbursement to CrownQuest pursuant to the terms of an administrative support agreement, were approximately $257 thousand and $207 thousand for the three months ended March 31, 2018 and 2017, respectively.

Unit incentive plan. The Second Amended and Restated Limited Partnership Agreement of Holdings dated January 4, 2018 (the "Holdings LP Agreement") provides for the granting of restricted unit awards to employees of CrownQuest in order to recognize and reward significant contributions. The incentive unit program is structured such that the unit awards are Class D LP Units and Class E LP Units and represent a profits interest in Holdings. In designating such units the Holdings LP Agreement authorized a maximum of 500,000 Class D Units and 300,000 Class E LP Units to be issued from time to time as determined by Holding's general partner (the Partnership's "ultimate general partner"). The unit incentive plan was previously administered by the Partnership prior to the merger with Holdings. The terms and conditions of the plan remain unchanged prior to and after the merger, except any restricted units are now issued by Holdings.

During the three months ended March 31, 2018, Holdings' general partner approved aggregate grants of 16,000 of Class E LP Units to non-officer employees of CrownQuest, subject to certain restrictions as set forth in the respective restricted unit agreements between Holdings and each such CrownQuest employee. No grants of Class D LP Units were made during the three months ended March 31, 2018. The restrictions lapse with respect to 100% of the restricted units seven years from the date of grant scheduled as no lapsing during the first two years followed by annual lapsing of 20% for the remaining five years. Prior to the merger, the Partnership maintained a similar incentive program. As a result of the merger, a modification occurred to the previous incentive units granted. In accordance with Accounting Standards Codification ("ASC") 718 – Compensation – Stock Compensation, no incremental compensation cost was recognized. During the three months ended March 31, 2017, the Partnership's general partner approved aggregate grants of 6,000 of Class D LP Units to officers and non-officer employees of CrownQuest. Since Class E LP Units were not established until June 19, 2017, no Class E LP Units were granted during the three months ended March 31, 2017.

L. Incentive Plans (Continued)

All restricted units are treated as issued and outstanding in the accompanying condensed consolidated balance sheets. If a CrownQuest employee terminates employment prior to the restriction lapse date, the awarded units are forfeited and canceled and are no longer considered issued and outstanding. A summary of the Partnership's restricted unit awards, comprised of Class D LP Units and Class E LP Units, for the three months ended March 31, 2018 is presented below:

	Class D LP Units		Class E LP Units	
	Number of Restricted Units	Grant Date Fair Value Per Unit	Number of Restricted Units	Grant Date Fair Value Per Unit
Restricted units:				
Outstanding at December 31, 2017	490,400	$ 57.89	5,000	$ 109.68
Units granted	-	-	16,000	109.68
Units canceled/forfeited	(3,300)	107.22	-	-
Outstanding at March 31, 2018	487,100	$ 57.56	21,000	$ 109.68

The following table summarizes information about unit-based compensation for restricted unit awards, recorded in the Partnership's consolidated financial statements, for the three months ended March 31, 2018 and 2017:

(in thousands)	**Three Months Ended March 31, 2018**	**2017**
Grant date fair value for awards during the period:		
Employee grants	$ 1,612	$ 742
Officer grants	-	-
Total	$ 1,612	$ 742
Unit-based compensation expense from restricted units:		
Employee grants	$ 878	$ 767
Officer grants	206	208
Total	$ 1,084	$ 975

The fair value of the units issued was determined utilizing a valuation provided by an independent third party consulting firm. The consulting firm derived the grant date fair value from this valuation by applying the distribution priority stated in the Holdings' LP Agreement. Such valuation is Level 3 within the fair value hierarchy. This valuation incorporates an income approach, a comparable transaction approach and a market approach to valuing the Partnership with numerous unobservable inputs, including pending and assumed transactions, estimated reserves and production rates, and other factors. Generally, a change in any of these inputs could lead to a change in the valuation of the grants.

L. Incentive Plans (Continued)

Future unit-based compensation expense. The following table reflects future unit-based compensation expense to be recorded for all the unit-based compensation awards that are outstanding at March 31, 2018. At March 31, 2018, this cost was expected to be recognized over a weighted-average period of approximately 4.3 years.

(in thousands)	Future Compensation
Remainder 2018	$ 3,250
2019	3,057
2020	2,467
2021	1,891
2022	1,352
Thereafter	1,323
Total	$ 13,340

M. Long-term Debt

The Partnership's debt consists of the following at March 31, 2018 and December 31, 2017:

	March 31, 2018	**December 31, 2017**
	(In thousands)	
5.625% unsecured senior notes due 2025	$ 1,000,000	$ 1,000,000
Unamortized deferred loan costs - senior notes	(11,716)	(12,105)
Construction loan - Canvasback office building	10,053	10,298
Unamortized deferred loan costs - construction loan	(189)	(195)
Total debt	998,148	997,998
Less current portion	(1,005)	(993)
Long-term debt	$ 997,143	$ 997,005

Credit facility. The Partnership's credit facility, as amended, (the "Credit Facility"), has a maturity date of April 1, 2020. In conjunction with its regular semiannual borrowing base redetermination, effective April 4, 2018, the Partnership elected to maintain a commitment amount of $500 million after being offered a borrowing base of $715 million by the lenders. Commitments from the Partnership's bank group total $1.0 billion. At March 31, 2018 and December 31, 2017, the Partnership had no advances or letters of credit outstanding under the Credit Facility.

Between scheduled borrowing base redeterminations, the Partnership and lenders, if requested by 66 2/3% of the lenders, may each request one special redetermination.

Advances on the Credit Facility bear interest, at the Partnership's option, based on (i) the prime rate of MUFG Union Bank, N.A. ("Union Bank Prime Rate") (4.75% at March 31, 2018) or (ii) Eurodollar rate (substantially equal to the London Interbank Offered Rate). The Credit Facility's interest rates on Eurodollar rate advances and Union Bank Prime Rate advances vary, with interest margins ranging from 250 to 350 basis points and 150 to 250 basis points, respectively, per annum depending on the debt balance outstanding. The Partnership pays commitment fees on the unused portion of the available commitment of 50 basis points per annum.

The Partnership's obligations under the Credit Facility are secured by a first lien on substantially all of its oil and natural gas properties. In addition, all of the Partnership's subsidiaries (excluding Abajo until such time as the Partnership owns 100% of the equity of Abajo) are guarantors, and the equity interests in such subsidiaries have been pledged to secure borrowings under the Credit Facility.

M. Long-term Debt (Continued)

If the outstanding principal balance of the loans under the Credit Facility exceeds the borrowing base at any time, the Partnership has the option to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, pledge additional collateral sufficient in the lenders' opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the ensuing five-month period.

The Credit Facility contains various restrictive covenants and compliance requirements, which include:

- maintenance of certain financial ratios, including:
  (i) maintenance of a quarterly ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations and including all line of credit obligations and any unfunded amounts under the Credit Facility, to be not less than 1.0 to 1.0,
  (ii) maintenance of a quarterly ratio of total funded indebtedness, net of unrestricted cash up to $100 million, to 12-month consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and noncash income and expenses to be no greater than 3.5 to 1.0, and
  (iii) maintenance of a quarterly ratio of 12-month consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and noncash income and expenses to 12-month consolidated interest expense to be not less than 3.0 to 1.0.
- delivery to the lender and maintenance of satisfactory title opinions covering not less than 80% and 85% of the present value of proved oil and natural gas reserves and proved developed producing oil and natural gas reserves, respectively;
- limits on the incurrence of additional indebtedness and certain types of liens;
- restrictions as to investments, mergers, acquisitions and dispositions of assets;
- restrictions on hedging contracts and transactions with affiliates; and
- limits on dividends and distributions. The agreement allows permitted tax distributions. It also allows periodic cash distributions if the Credit Facility usage is equal to or less than 80% of the elected commitment amount and the Partnership's funded indebtedness, net of unrestricted cash up to $100 million, to 12-month consolidated earnings before interest expense, income taxes, depletion, depreciation and amortization, exploration expense and non-cash income and expenses is no more than 2.75 to 1.00. The agreement allows cash distributions in 2018 not to exceed $25 million, irrespective of the limit stated above.

At March 31, 2018, the Partnership was in compliance with all of the covenants under the Credit Facility, as amended.

5.625% Senior Notes due 2025. On October 11, 2017, the Partnership and CrownRock Finance issued $1.0 billion aggregate principal amount of 5.625% senior unsecured notes due 2025 at par (the "2025 Senior Notes"). The Partnership issued the 2025 Senior Notes to fund the tender offers and redemptions of the 7.125% Senior Notes due 2021 and the 7.75% Senior Notes due 2023, pay off advances on the Credit Facility, and for general partnership purposes, including the funding of a portion of its capital development plan. The 2025 Senior Notes mature on October 15, 2025, and interest is paid in arrears semiannually on April 15 and October 15 beginning April 15, 2018. The 2025 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by Roddy and Canvasback. The notes may be redeemed on or after the following dates and at the following redemption prices, expressed as a percentage of principal amount plus accrued and unpaid interest if any, during the periods indicated: October 15, 2020, 104.219%; October 15, 2021, 102.813%; October 15, 2022, 101.406%; October 15, 2023, 100.00%.

The 2025 Senior Notes are general, unsecured senior obligations and are subordinated to all existing and future secured indebtedness, including the Credit Facility. The indenture to the 2025 Senior Notes dated as of October 11, 2017 contains various restrictive covenants which include:

M. Long-term Debt (Continued)

- limits on the incurrence of additional indebtedness and certain types of liens;
- restrictions as to mergers and disposition of assets;
- limits on transactions with affiliates; and
- limits on dividends and distributions. The agreement allows permitted tax distributions and periodic cash distributions up to $150 million plus 50 % of consolidated net income as adjusted for certain non-cash items pursuant to the provisions of the indenture governing the 2025 Senior Notes ("Senior Note Indenture") from July 1, 2017 to the end of the Partnership's most recently ended fiscal quarter.

At March 31, 2018, the Partnership was in compliance with all of the covenants under the indenture to the 2025 Senior Notes.

Construction loan - Canvasback office building. On June 19, 2014, Canvasback entered into a construction loan agreement with a bank (the "Construction Loan") to partially finance the cost of the construction of an office building in Midland, Texas that became the Partnership's headquarters. Advances were made during the period of February 2015 through December 2015 when the final advance was made and the balance outstanding was at its maximum amount available of $12.0 million.

Advances on the Construction Loan bear interest at the fixed rate of 4.75% for the period of June 19, 2014 through June 30, 2020 and then reset and become fixed at the Wall Street Journal published prime rate in effect on July 1, 2020 plus 150 basis points for the period of July 1, 2020 through June 30, 2026.

Payments of interest only were paid monthly during the construction phase beginning September 1, 2014 through February 1, 2016. Construction was completed and the certain conditions of the loan agreement were satisfied in December 2015 to effect the extension of the loan to June 30, 2026. In accordance with the terms of the Construction Loan, commencing on March 1, 2016, payments of principal and interest are due on the first of each month in an amount necessary to fully amortize the loan over its remaining term.

The Construction Loan is secured by a mortgage on the office building. The Partnership unconditionally guarantees Canvasback's payments and performance on the loan.

Principal maturities of debt. The Credit Facility expires in 2020. The 2025 Senior Notes are due in 2025.

Interest expense. The following amounts have been incurred and charged to interest expense for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Cash payments for interest	$ 753	$ 14,327
Amortization of original issue discount	-	134
Amortization of deferred loan costs	668	748
Net changes in accrued interest expense	14,063	433
Total interest expense	$ 15,484	$ 15,642

N. Exchanges

Occasionally, if it is deemed value-adding, the Partnership will enter into exchange agreements with competitors to trade undeveloped acreage as part of its strategy to consistently pursue financially viable deals to further enhance its horizontal well drilling inventory in the Permian Basin. The Partnership did not consummate any significant exchanges during the three months ended March 31, 2018. The Partnership consummated several such exchanges during 2017 as shown below.

On August 1, 2017, the Partnership exchanged approximately 3,297 gross (2,079 net) acres of undeveloped acreage located in Glasscock and Midland counties, Texas to a third party in exchange for approximately 7,036 gross (1,461 net) acres of undeveloped acreage located in Glasscock, Midland, and Upton counties, Texas. The exchange enhanced the Partnership's acreage position and horizontal well inventory in the Midland Basin. The effective date of the exchange was August 1, 2017. This transaction represented a partial exchange of unproved property. No gain or loss was recognized.

On June 30, 2017, the Partnership exchanged approximately 3,407 gross (2,302 net) acres of developed and undeveloped acreage and working interests in 26 gross (23.4 net) producing wells located in the Martin and Howard counties, Texas to a third party in exchange for approximately 2,263 gross (2,182 net) acres of developed and undeveloped acreage and working interests in 23 gross (23 net) producing wells also located in Martin and Howard counties, Texas and $85 thousand in cash. The exchange enhanced the Partnership's acreage position and horizontal well inventory in these two counties. The effective date of the exchange was May 1, 2017. This transaction represented a partial exchange of both proved and unproved property. A gain of $55 thousand was recognized in the statement of operations. For the year ended December 31, 2016, oil and natural gas revenue from the assets the Partnership traded to the third party was approximately $3.6 million and they produced an average of approximately 438 Boe per day, of which 38% was crude oil.

On January 18, 2017, the Partnership entered into an agreement with a third party in which it exchanged approximately 6,552 gross (4,056 net) acres of developed and undeveloped oil and natural gas properties and 50 gross (29.2 net) producing wells located in Midland and Glasscock counties, Texas for 14,600 gross (2,332 net) acres of developed and undeveloped oil and natural gas properties and 68 gross (8.9 net) producing wells located in Midland County, Texas and $6.6 million in cash. The exchange enhanced the Partnership's acreage position and horizontal well drilling inventory in Midland County. The effective date of the exchange was January 1, 2017. This transaction represented a partial exchange of both proved and unproved property. A gain of $4.9 million was recognized in the statement of operations. For the year ended December 31, 2016, oil and natural gas revenue from the assets the Partnership traded to the third party was approximately $8.0 million and they produced an average of approximately 1,196 Boe per day, of which 42% was crude oil.

O. Supplemental Guarantor Information

One of CrownRocks's wholly-owned subsidiaries, CrownRock Finance, is a co-issuer of the 2025 Senior Notes. Two of CrownRock's wholly-owned subsidiaries, Roddy and Canvasback, guarantee the 2025 Senior Notes. Such guarantees are joint and several, full and unconditional except for customary release provisions.

The Partnership has prepared Condensed Consolidating Financial Statements in order to quantify the assets, results of operations and cash flows of each of the Partnership's subsidiaries including the subsidiary co-issuer and guarantors. Abajo is shown in these Condensed Consolidating Financial Statements; however Abajo does not guarantee the Senior Notes.

The following Condensed Consolidating Balance Sheets at March 31, 2018 and December 31, 2017 and Condensed Consolidating Statements of Operations and Condensed Consolidating Statements of Cash Flows for the three months ended March 31, 2018 and 2017, present financial information for CrownRock, L.P., on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiaries, including the subsidiary co-issuer (CrownRock Finance), subsidiary guarantors (Roddy and Canvasback) and the subsidiary non-guarantor (Abajo), on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Partnership on a consolidated basis.

O. Supplemental Guarantor Information (Continued)

	As of March 31, 2018						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
Condensed Balance Sheet				(In thousands)			
Assets							
Cash and cash equivalents	$ 51,947	$ 977	$ -	$ 50	$ 135	$ -	$ 53,109
Accounts receivable – related party	57,267	290	-	46	8	(190)	57,421
Other current assets	3,581	99	-	-	12	-	3,692
Derivative instruments	43,961	-	-	-	-	-	43,961
Oil and natural gas properties	1,764,779	1,798	-	-	-	-	1,766,577
Other property and equipment	68,105	-	-	25,383	907	-	94,395
Deferred loan costs	2,245	-	-	-	-	-	2,245
Noncurrent derivative instruments	13,426	-	-	-	-	-	13,426
Other assets	7,993	43	-	-	-	-	8,036
Investment in Abajo, LLC	444	-	-	-	-	(444)	-
Investment in Canvasback Properties, LLC	15,592	-	-	-	-	(15,592)	-
Investment in Roddy, LLC	2,199	-	-	-	-	(2,199)	-
Total Assets	**$ 2,031,539**	**$ 3,207**	**$ -**	**$ 25,479**	**$ 1,062**	**$ (18,425)**	**$ 2,042,862**
Liabilities and Partners' Capital							
Accounts payable & accrued liabilites - related party	$ 24,421	$ 13	$ -	$ -	$ 193	$ (190)	$ 24,437
Accrued interest payable	26,563	-	-	-	-	-	26,563
Current portion of long-term debt	-	-	-	1,005	-	-	1,005
Other current liabilities	817	-	-	23	-	-	840
Long-term debt	988,284	-	-	8,859	-	-	997,143
Asset retirement obligations	19,705	995	-	-	-	-	20,700
Total liabilities	**$ 1,059,790**	**$ 1,008**	**$ -**	**$ 9,887**	**$ 193**	**$ (190)**	**$ 1,070,688**
CrownRock, L.P. Partners' Capital	971,749	2,199	-	15,592	869	(18,660)	971,749
Non-controlling interest in subsidiary	-	-	-	-	-	425	425
Total Liabilities and Partners' Capital	**$ 2,031,539**	**$ 3,207**	**$ -**	**$ 25,479**	**$ 1,062**	**$ (18,425)**	**$ 2,042,862**

	As of December 31, 2017						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
Condensed Balance Sheet				(In thousands)			
Assets							
Cash and cash equivalents	$ 94,873	$ 967	$ -	$ 90	$ 137	$ -	$ 96,067
Accounts receivable – related party	43,272	369	-	-	-	(190)	43,451
Other current assets	4,810	99	-	-	19	-	4,928
Derivative instruments	59,044	-	-	-	-	-	59,044
Oil and natural gas properties	1,653,361	1,815	-	-	-	-	1,655,176
Other property and equipment	67,469	-	-	24,985	955	-	93,409
Deferred loan costs	2,519	-	-	-	-	-	2,519
Other assets	6,224	43	-	-	-	-	6,267
Investment in Abajo, LLC	474	-	-	-	-	(474)	-
Investment in Canvasback Properties, LLC	14,956	-	-	-	-	(14,956)	-
Investment in Roddy, LLC	2,213	-	-	-	-	(2,213)	-
Total Assets	**$ 1,949,215**	**$ 3,293**	**$ -**	**$ 25,075**	**$ 1,111**	**$ (17,833)**	**$ 1,960,861**
Liabilities and Partners' Capital							
Accounts payable & accrued liabilites - related party	$ 7,037	$ 95	$ -	$ -	$ 182	$ (189)	$ 7,125
Accrued interest payable	12,500	-	-	-	-	-	12,500
Current portion of long-term debt	-	-	-	993	-	-	993
Other current liabilities	909	-	-	15	-	-	924
Long-term debt	987,895	-	-	9,110	-	-	997,005
Noncurrent derivative instruments	1,241	-	-	-	-	-	1,241
Asset retirement obligations	19,087	985	-	-	-	-	20,072
Other noncurrent liabilities	555	-	-	-	-	-	555
Total liabilities	**1,029,224**	**1,080**	**-**	**10,118**	**182**	**(189)**	**1,040,415**
CrownRock, L.P. Partners' Capital	919,991	2,213	-	14,957	929	(18,099)	919,991
Non-controlling interest in subsidiary	-	-	-	-	-	455	455
Total Liabilities and Partners' Capital	**$ 1,949,215**	**$ 3,293**	**$ -**	**$ 25,075**	**$ 1,111**	**$ (17,833)**	**$ 1,960,861**

O. Supplemental Guarantor Information (Continued)

	For the Three Months Ended March 31, 2018						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Condensed Statement of Operations							
Revenues:							
Oil and natural gas sales, rental income, transportation, SWD income, surface ownership and fresh water supply income	$ 141,936	$ 355	$ -	$ 568	$ 9	$ (568)	$ 142,300
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	28,350	342	-	-	3	-	28,695
Exploration costs	5	-	-	-	-	-	5
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	44,934	27	-	194	48	-	45,203
General and administrative	6,290	-	-	1	18	(567)	5,742
Operating income (loss)	62,357	(14)	-	373	(60)	(1)	62,655
Gain on derivatives not designated as hedges	8,550	-	-	-	-	-	8,550
Interest expense	(15,357)	-	-	(127)	-	-	(15,484)
Other income (expense)	295	-	-	40	-	(241)	94
Net income (loss)	55,845	(14)	-	286	(60)	(242)	55,815
Net loss attributable to non-controlling interest	-	-	-	-	-	30	30
Net income (loss) attributable to CrownRock, L.P.	$ 55,845	$ (14)	$ -	$ 286	$ (60)	$ (212)	$ 55,845
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ 55,845	$ (14)	$ -	$ 286	$ (60)	$ (242)	$ 55,815
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	30	30
Comprehensive income (loss) attributable to CrownRock, L.P.	$ 55,845	$ (14)	$ -	$ 286	$ (60)	$ (212)	$ 55,845

	For the Three Months Ended March 31, 2017						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Condensed Statement of Operations							
Revenues:							
Oil and natural gas sales, rental income, transportation and SWD income	$ 69,678	$ 316	$ -	$ 535	$ 17	$ (535)	$ 70,011
Gain on sale of oil and gas properties	5,354	-	-	-	-	-	5,354
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	19,991	308	-	-	3	-	20,302
Exploration costs	3,072	-	-	-	-	-	3,072
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	32,772	27	-	180	48	-	33,027
General and administrative	5,472	-	-	-	16	(535)	4,953
Operating income (loss)	13,725	(19)	-	355	(50)	-	14,011
Gain on derivatives not designated as hedges	31,476	-	-	-	-	-	31,476
Interest expense	(15,504)	-	-	(138)	-	-	(15,642)
Other income (expense)	65	(108)	-	-	-	(65)	(108)
Net income (loss)	29,762	(127)	-	217	(50)	(65)	29,737
Net loss attributable to non-controlling interest	-	-	-	-	-	25	25
Net income (loss) attributable to CrownRock, L.P.	$ 29,762	$ (127)	$ -	$ 217	$ (50)	$ (40)	$ 29,762
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ 29,762	$ (127)	$ -	$ 217	$ (50)	$ (65)	$ 29,737
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	25	25
Comprehensive income (loss) attributable to CrownRock, L.P.	$ 29,762	$ (127)	$ -	$ 217	$ (50)	$ (40)	$ 29,762

O. Supplemental Guarantor Information (Continued)

Condensed Statement of Cash Flows	For the Three Months Ended March 31, 2018						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Cash flows from operating activities	$ 100,253	$ 10	$ -	$ 441	$ (1)	$ -	$ 100,703
Cash flows from investing activities:							
Acquisition of leasehold and oil and natural gas properties	(1,633)	-	-	-	-	-	(1,633)
Capital expenditures on oil and natural gas properties	(138,102)	-	-	-	-	-	(138,102)
Additions to other property and equipment	(1,102)	-	-	(586)	-	-	(1,688)
Contributions to equity method investments	(1,782)	-	-	-	-	-	(1,782)
Investment in subsidiary	(350)	-	-	-	-	350	-
Total cash flows from investing activities	$ (142,969)	$ -	$ -	$ (586)	$ -	$ 350	$ (143,205)
Cash flows from financing activities:							
Capital contribution from parent	-	-	-	350	-	(350)	-
Repayments of long-term borrowings under construction loan	-	-	-	(245)	-	-	(245)
Payments for loan and debt issue costs	(182)	-	-	-	-	-	(182)
Purchase of treasury units	(29)	-	-	-	-	-	(29)
Total cash flows from financing activities	$ (211)	$ -	$ -	$ 105	$ -	$ (350)	$ (456)
Net increase (decrease) in cash and cash equivalents	$ (42,927)	$ 10	$ -	$ (40)	$ (1)	$ -	$ (42,958)
Cash and cash equivalents, beginning of period	94,874	967	-	90	136	-	96,067
Cash and cash equivalents, end of period	$ 51,947	$ 977	$ -	$ 50	$ 135	$ -	$ 53,109

Condensed Statement of Cash Flows	For the Three Months Ended March 31, 2017						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Cash flows from operating activities	$ 55,527	$ (88)	$ -	$ 402	$ 2	$ -	$ 55,843
Cash flows from investing activities:							
Acquisition of leasehold and oil and natural gas properties	(5,097)	-	-	-	-	-	(5,097)
Capital expenditures on oil and natural gas properties	(76,894)	100	-	-	-	-	(76,794)
Additions to other property and equipment	(2,527)	-	-	-	-	-	(2,527)
Proceeds from sale/exchange of oil and natural gas properties	7,247	-	-	-	-	-	7,247
Investment in subsidiary	-	-	-	-	-	-	-
Total cash flows from investing activities	$ (77,271)	$ 100	$ -	$ -	$ -	$ -	$ (77,171)
Cash flows from financing activities:							
Capital contribution from parent	-	-	-	-	-	-	-
Distributions to parent	-	-	-	-	-	-	-
Repayments from long-term borrowings under construction loan	-	-	-	(234)	-	-	(234)
Payments for loan costs	9	-	-	-	-	-	9
Purchase of treasury units	(4,920)	-	-	-	-	-	(4,920)
Total cash flows from financing activities	$ (4,911)	$ -	$ -	$ (234)	$ -	$ -	$ (5,145)
Net increase (decrease) in cash and cash equivalents	$ (26,655)	$ 12	$ -	$ 168	$ 2	$ -	$ (26,473)
Cash and cash equivalents, beginning of period	121,965	1,591	-	50	173	-	123,779
Cash and cash equivalents, end of period	$ 95,310	$ 1,603	$ -	$ 218	$ 175	$ -	$ 97,306

P. Subsequent Events

New commodity derivative contracts. After March 31, 2018 and through May 10, 2018, the Partnership entered into the following oil price commodity derivative contracts to hedge an additional portion of its estimated future oil production:

	Aggregate Volume	Price Per Bbl	Contract Period
Oil (volumes in Bbls):			
Price swap (a)	1,026,000	$ 61.49	1/1/19 - 3/31/19
Price swap	2,184,000	$ 62.18	4/1/19 - 6/30/19
Price swap	1,518,000	$ 61.31	7/1/19 - 9/30/19
Price swap	598,000	$ 60.88	10/1/19 - 12/31/19
Basis swap (b)	1,288,000	$ (3.30)	7/1/19 - 12/31/19

(a) The index prices for the oil price swaps are based on the NYMEX - West Texas Intermediate monthly average futures price.
(b) The basis differential price is between Midland - WTI and Cushing - WTI.

Commodity derivative contracts at May 10, 2018. The following table sets forth the Partnership's outstanding commodity derivative contracts, by quarter of settlement, at May 10, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2018:					
Volume (Bbl)		1,783,600	2,033,200	2,162,000	5,978,800
Price per Bbl		$ 67.84	$ 68.78	$ 67.81	$ 68.15
2019:					
Volume (Bbl)	2,178,000	2,184,000	1,518,000	598,000	6,478,000
Price per Bbl	$ 60.94	$ 62.18	$ 61.31	$ 60.88	$ 61.44
Oil Basis Swaps: (b)					
2018:					
Volume (Bbl)		819,000	552,000	552,000	1,923,000
Price per Bbl		$ 0.07	$ -	$ -	$ 0.03
2019:					
Volume (Bbl)	1,890,000	2,275,000	2,944,000	2,944,000	10,053,000
Price per Bbl	$ (0.35)	$ (0.35)	$ (1.00)	$ (1.00)	$ (0.73)
2020:					
Volume (Bbl)	1,092,000	1,092,000	1,104,000	1,104,000	4,392,000
Price per Bbl	$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)	$ (0.15)

(a) The index prices for the oil price swaps are based on the NYMEX - West Texas Intermediate monthly average futures price.
(b) The basis differential price is between Midland - WTI and Cushing - WTI.

* * * * * * * * * * * * * * * * * * * *

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with consolidated financial statements and related notes included elsewhere in this report and with our financial statements in our annual report for the year ended December 31, 2017. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in the forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Information," all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are an independent oil and natural gas partnership engaged in the acquisition, development and exploration of oil and natural gas properties. Our assets are located in Texas, New Mexico and Utah, and our operations are primarily focused on the development of our core Permian Basin assets. We intend to grow our reserves and production through development drilling and exploration activities on our multi-year project inventory and through acquisitions or exchanges that meet our strategic and financial objectives.

Our core properties are in the Northern Midland Basin in the Permian Basin of West Texas where we intend to focus primarily on drilling horizontal targets on multiple benches. The Permian Basin of West Texas is characterized by an extensive production history, predominantly oil-focused drilling targets, abundant infrastructure, wells with long reserve lives and multiple production horizons. The Wolfberry play is a modification and extension of the Spraberry play, while the Wolfcamp and Spraberry shale play utilizes horizontal drilling in the historic Spraberry play, the majority of which is designated in the Spraberry Trend Area Field. According to the latest information available from the Energy Information Administration of the U.S. Department of Energy, the Spraberry Trend Area ranks as the second largest oilfield in the United States by proved reserves and by estimated oil production. Based on the returns we have generated through our drilling efforts to date, the number of undrilled locations in our drilling plan, and our observation of the activity and results of other operators in this area, we believe the Midland Basin represents one of the premier oil and gas development opportunities in North America. From October 2007 through December 2014, we primarily focused on drilling vertical wells in the Midland Basin. In January 2015, we initiated our horizontal program, with our first horizontal well coming on line in March 2015. We spent much of 2016 preparing to accelerate our horizontal activity. This included identifying potential horizontal drilling locations plus identifying optimum spacing between wells, including interval spacing between zones or benches. During 2017, we increased horizontal drilling, and drilled approximately 60% more horizontal wells as compared to 2016. We continued to engineer our optimal spacing development program, which resulted in a build-up of an inventory of drilled but uncompleted wells in order to concurrently complete wells in each spacing unit block.

Our other properties are located in different parts of the Permian Basin of West Texas and New Mexico, in Mitchell County on the Permian Basin's Eastern Shelf and in Andrews and Gaines Counties on the Permian Basin's Central Basin Platform, as well as acreage in the San Juan Basin of New Mexico and the Paradox Basin of Utah.

Financial and Operating Performance

Our financial and operating performance for the three months ended March 31, 2018, as compared to the three months ended March 31, 2017 included the following highlights:

- Net income attributable to the Partnership increased by $26.0 million to net income of $55.8 million for the first three months in 2018, as compared to net income of $29.8 million for the first three months in 2017. The increase in earnings is primarily due to:

- a $68.5 million increase in oil and natural gas revenues as a result of a 33% increase in commodity prices (oil equivalent, excluding derivatives) and a 50% increase in production (oil equivalent);

- $5 thousand in exploration costs during 2018, as compared to $3.0 million during 2017;

- $0.6 million in impairment expense during 2018, as compared to $2.0 million during 2017;

- offset by:

  - an $8.4 million increase in oil and natural gas production costs in 2018 due to increases in lease operating expenses and production taxes;

  - a $13.5 million increase in depreciation, depletion and amortization due to increased capitalized costs associated with the new wells that were successfully drilled and completed in 2017 and 2018;

  - a $8.6 million gain on derivatives during the first three months in 2017, comprised of $9.0 million gain on cash settlements offset by a $0.4 million mark-to-market loss primarily the result of increases in forward looking crude oil prices, as compared to a $31.5 million gain in the first three months in 2017, comprised of $26.8 million gain on cash settlements and a $4.7 million mark-to-market gain; and

  - a $1.5 million decrease in other revenue and gain on sales and exchanges of oil and natural gas properties during the first three months in 2018 as compared to the first three months in 2017.

- Average daily sales volumes increased during the first three months of 2018 by 50% from 21,851 Boe per day during the first three months in 2017 to 32,707 Boe per day during the first three months in 2018.

- Net cash provided by operating activities increased by $44.9 million to $100.7 million for the first three months in 2018, as compared to $55.8 million for the first three months in 2017, principally due to increases in oil and natural gas revenues and changes in working capital items offset by decreases in cash settlements on crude oil derivatives.

- At March 31, 2018, we had no amounts outstanding and our availability under our credit facility was $500 million.

Commodity Prices

Although oil, NGL and natural gas prices rose during 2017, oil, NGL and natural gas prices have historically been volatile, and we expect this price volatility to continue in the future. During the five years ended December 31, 2017, NYMEX WTI oil futures contract prices ranged from a high of $107.26 per barrel on June 20, 2014 to a low of $26.21 per barrel on February 11, 2016, and NYMEX Henry Hub gas futures prices ranged from a high of $6.15 MMBtu on February 19, 2014 to a low of $1.64 per MMBtu on March 3, 2016. As of December 31, 2017, NYMEX WTI oil futures contract prices and NYMEX Henry Hub gas futures prices were $60.42 per barrel and $2.95 per MMBtu, respectively. NGL prices have fluctuated similarly. While we have hedged a portion of our projected oil production through the third quarter of 2019, our average realized prices for oil could decrease if oil prices decline. However, because we elected a borrowing base of $500.0 million for our revolving credit facility, instead of the maximum potential amount of $715.0 million, we do not expect any near term negative impact to our elected borrowing base due to lower commodity prices.

Lower commodity prices may result in reductions in revenues, net income and cash flows from operating activities. As a result, our historical financial statements may not be indicative of expected future results.

Our results of operations are heavily influenced by commodity prices. Oil, NGL and natural gas prices may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, NGL and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the level of consumer demand, domestic and worldwide, for oil, NGL and natural gas;
- the domestic and worldwide supply of oil, NGL and natural gas;
- inventory levels at Cushing, Oklahoma, the benchmark for WTI oil prices;
- natural gas inventory levels in the United States;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and quantity of foreign imports of oil, NGL and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries and other state-controlled oil companies to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxation;
- the price, availability and acceptance of alternative fuel sources;
- the effect of energy conservation efforts;
- weather conditions;
- the effect of oil and LNG imports to and exports from the United States;
- political conditions or hostilities in oil, NGL and natural gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption and energy supply;
- variations between product prices at sales points and applicable index prices; and
- worldwide economic conditions.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we will continue to economically hedge a portion of our commodity price risk to mitigate the effect of price volatility on our business.

Property Exchanges

Exchanges

Occasionally, if it is deemed value-adding, we will enter into exchange agreements with competitors to trade developed and undeveloped acreage as part of its strategy to consistently pursue financially viable deals to further enhance its horizontal well drilling inventory in the Permian Basin. We did not consummate any significant property exchanges during the three months ended March 31, 2018.

Recent Events

Oil, NGL and natural gas price volatility. Prices for our products have continued to be volatile. Although oil prices were moderately higher and gas prices were slightly lower during the three months ended March 31, 2018 as compared to the year ended December 31, 2017, ongoing fluctuations have made it difficult to assess price stability. For the three months ended March 31, 2018, the average NYMEX – WTI futures price of crude oil was $62.89 per Bbl and the average NYMEX – Henry Hub futures price of natural gas was $2.85 per MMBtu, representing a 24% increase in oil price and a 6% decrease in gas price, from the averages of $50.85 per Bbl of oil and $3.02 per MMBtu for natural gas for the year ended December 31, 2017. Although we have hedged a portion of our estimated oil and natural gas production through the third quarter of 2019, we may still be adversely affected by continuing and prolonged declines in the price of oil and natural gas. We have planned our 2018 capital expenditures based upon our expectations of the current and future pricing environment. Further, we have continued to maintain a low cost structure and adequate liquidity to allow us to continue to operate efficiently and expand in the current price environment.

Merger Transactions. Effective January 1, 2018, we merged with a subsidiary of CrownRock Holdings, L.P. ("Holdings"), a Delaware limited partnership formed by affiliates of management and Lime Rock. As a result of this merger, we and our general partner became wholly-owned subsidiaries of Holdings. We admitted Holdings as our sole limited partner and cancelled all our other limited partner interests comprised of Class A, B, C, D and E limited partnership units. Holdings issued equivalent units of equivalent classes to our former limited partners of the Partnership. As the ownership of the Partnership was identical prior to and after the merger, it was considered a transaction between entities under common control. Additionally, effective January 1, 2018, the Partnership executed the Second Amended and Restated Partnership Agreement to provide for sole control and management of the Partnership by the general partner and the simplification of the governance of the Partnership.

CrownRock Holdings, L.P. Issuance of Series A Preferred Units. On January 4, 2018, Holdings issued 475,000 Series A Preferred Units to investors for a purchase price of $1,000 per Preferred Unit. After payment of fees and expenses, the net proceeds from this sale in the amount of $454.0 million were distributed by Holdings to its limited partners. The Series A Preferred Units are perpetual and have a coupon dividend rate of 6.0% per annum for the first eight years and 9.0% per annum thereafter, paid quarterly. Dividends will accrue and accumulate until paid in full. For the first three years, Holdings may elect to pay the quarterly dividends in kind with the issuance of additional Series A Preferred Units. The dividends must be paid in cash thereafter. Although Holdings may elect to pay the dividends in kind during the first three years, Holdings must make quarterly tax distributions to the holders of the Series A Preferred Units in cash beginning with the quarter ending March 31, 2018. We expect the amount of such tax distributions for 2018 will be approximately $22.5 million. Since Holdings' only asset is its ownership of the Partnership and the Partnership's general partner, the funds Holdings requires to pay the quarterly tax distributions will be obtained from the Partnership paying quarterly distributions to Holdings. Our credit facility and the indenture governing our 2025 Senior Notes have restrictive covenants limiting dividends and distributions. We estimate that we can pay the necessary quarterly tax distributions to Holdings within the limits of these two agreements.

In addition, in certain circumstances involving a change of control or an initial public offering, Holdings must redeem the Series A Preferred Units in cash. However, the Series A Preferred Units are not generally redeemable at the option of the holder.

CrownRock Holdings, L.P. Distributions. After January 1, 2018, distributions will be made solely to Holdings as our sole limited partner. Holdings must make quarterly tax distributions in cash to certain of its unitholders beginning with the quarter ending March 31, 2018. The amount of such tax distributions for 2018 is expected to be approximately $22.5 million. Since Holdings' only asset is its ownership of us and our general partner, the funds Holdings requires to pay the quarterly tax distributions will be obtained from us paying quarterly distributions to Holdings. To provide Holdings with funds required to make its quarterly tax distribution, we distributed $5.2 million to Holdings on April 13, 2018. Our credit facility and the indenture governing its 2025 Senior Notes have restrictive covenants limiting dividends and distributions (See Note M – Long-term Debt). We estimate that we can pay the necessary quarterly tax distributions to Holdings within the limits of these two agreements

Redetermination of borrowing base. In conjunction with our regular semiannual borrowing base redetermination on our Credit Facility, effective April 4, 2018, we elected to maintain a commitment amount of $500 million after being offered a borrowing base of $715 million by our lenders. The offered borrowing base amount represents an increase of $125 million from the previously offered borrowing base of $590 million.

Derivative Financial Instruments

Derivative financial instrument exposure. At March 31, 2018, the fair value of our financial derivatives was a net asset of $57.4 million. All of our counterparties to these financial derivatives are a party to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable.

Selected Oil and Natural Gas Information

Productive wells. The following table sets forth information at March 31, 2018 relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian Basin	840	112	952	646.5	80.7	727.2
San Juan Basin	6	52	58	6.0	34.0	40.0
Paradox Basin	1	2	3	0.4	1.2	1.6
Total	847	166	1,013	652.9	115.9	768.8

The following table sets forth the number of productive oil and natural gas wells attributable to our properties as of December 31, 2017.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian Basin	792	120	912	599.4	88.9	688.3
San Juan Basin	6	50	56	6.0	32.3	38.3
Paradox Basin	-	2	2	-	1.2	1.2
Total	798	172	970	605.4	122.4	727.8

Results of Operations

The following table sets forth production and operating data for the three months ended March 31, 2018 and 2017.

	For the Three Months Ended March 31,	
	2018	2017
Net production volumes:		
Oil (Bbl)	1,882,893	1,087,367
Natural gas (Mcf)	2,558,450	2,236,521
Natural gas liquids (Bbl)	634,293	506,436
Oil equivalent (Boe)	2,943,594	1,966,557
Average daily production volumes:		
Oil (Bbl)	20,921	12,082
Natural gas (Mcf)	28,427	24,850
Natural gas liquids (Bbl)	7,048	5,627
Oil equivalent (Boe)	32,707	21,851
Average prices:		
Oil, without derivatives ($/Bbl)	$ 63.68	$ 50.80
Oil, with derivatives ($/Bbl) (a)	$ 68.44	$ 75.41
Natural gas, without derivatives ($/Mcf)	$ 1.79	$ 2.35
Natural gas liquids, without derivatives ($/Bbl)	$ 20.41	$ 16.74
Oil equivalent, without derivatives ($/Boe)	$ 46.69	$ 35.07
Oil equivalent, with derivatives ($/Boe) (a)	$ 49.73	$ 48.68
Operating costs and expenses per Boe:		
Lease operating expenses and workover costs	$ 7.01	$ 7.86
Oil and natural gas production and ad valorem taxes	$ 2.74	$ 2.46
Depreciation, depletion and amortization	$ 15.06	$ 15.68
General and administrative	$ 1.95	$ 2.52

(a) Includes the effect of the cash receipts from commodity derivatives not designated as hedges and reported in other income and expenses. The following table reflects the amounts of cash settlements received from commodity derivatives not designated as hedges that were included in computing average prices with hedges.

	For the Three Months Ended March 31,	
(in thousands)	2018	2017
Cash receipts from derivatives not designated as hedges:		
Oil derivatives	$ 8,966	$ 26,756

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash payments on/receipts from commodity derivatives that are presented in gain (loss) on derivatives not designated as hedges in the statements of operations. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017

Oil and natural gas revenues.

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Oil sales	$ 119,898	$ 55,242
Natural gas sales	4,580	5,252
Natural gas liquids sales	12,945	8,477
Total oil and natural gas sales	$ 137,423	$ 68,971

Revenue from oil and natural gas operations was $137.4 million for the three months ended March 31, 2018, an increase of $68.4 million (99%) from $69.0 million for the three months ended March 31, 2017. This increase was primarily due to a 33% increase in oil, natural gas and natural gas liquids prices (oil equivalent excluding the effects of derivative activities) during 2018 as compared to 2017 and a 50% increase in production (oil equivalent) as a result of increased drilling and completion activity during the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. Specifics include the following:

- the average realized oil price (excluding the effects of derivative activities) was $63.68 per Bbl during the three months ended March 31, 2018, an increase of 25% from $50.80 per Bbl during the three months ended March 31, 2017;
- total oil production was 1,882,893 Bbl for the three months ended March 31, 2018, an increase of 795,526 Bbl (73%) from 1,087,367 Bbl for the three months ended March 31, 2017;
- the average realized natural gas price (excluding the effects of derivative activities) was $1.79 per Mcf during the three months ended March 31, 2018, a decrease of 24% from $2.35 per Mcf during the three months ended March 31, 2017;
- total natural gas production was 2,558,450 Mcf for the three months ended March 31, 2018, an increase of 321,929 Mcf (14%) from 2,236,521 Mcf for the three months ended March 31, 2017;
- the average realized natural gas liquids price (excluding the effects of derivative activities) was $20.41 per Bbl during the three months ended March 31, 2018, an increase 22% from $16.74 per Bbl during the three months ended March 31, 2017; and
- total natural gas liquids production was 634,293 Bbl for the three months ended March 31, 2018, an increase of 127,857 Bbl (25%) from 506,436 Bbl for the three months ended March 31, 2017.

Production expenses. The following table provides the components of our total oil and natural gas production expenses for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,			
	2018		2017	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 20,624	$ 7.01	$ 15,458	$ 7.86
Production and ad valorem taxes	8,071	2.74	4,844	2.46
Total oil and natural gas production expenses	$ 28,695	$ 9.75	$ 20,302	$ 10.32

Among the cost components of production expenses, in general, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses. Lease operating expenses were $20.6 million ($7.01 per Boe) for the three months ended March 31, 2018 which was an increase of $5.1 million (33%) from $15.5 million ($7.86 per Boe) for the three months ended March 31, 2017. The increase in lease operating expenses was due to the increase in the number of wells being placed in service as a result of successful drilling efforts during 2018 and 2017 coupled with an increase in well servicing costs on downhole and surface equipment. These servicing costs increased 47% (on a per Boe basis) which approximated $4.4 million ($1.50 per Boe) for the three months ended March 31, 2018 as compared to approximately $2.0 million ($1.02 per Boe) for the three months ended March 31, 2017. The decrease in lease operating expenses per Boe was primarily due to an increase in production period over period.

Production and ad valorem taxes. The Partnership recorded production and ad valorem taxes of $8.1 million for the three months ended March 31, 2018, as compared to $4.8 million for the three months ended March 31, 2017. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, ad valorem taxes are based upon prior year commodity prices; whereas production taxes are based upon current year commodity prices.

The following table provides the Partnership's production and ad valorem taxes per BOE for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31,			
	2018		2017	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
Production taxes	$ 6,625	$ 2.25	$ 3,583	$ 1.82
Ad Valorem taxes	1,446	0.49	1,261	0.64
Total production and ad valorem taxes	$ 8,071	$ 2.74	$ 4,844	$ 2.46

Production taxes per unit of production were $2.25 per Boe for the three months ended March 31, 2018, an increase of 24% from $1.82 per Boe for the three months ended March 31, 2017. The oil revenue/gas revenue components of total revenue from oil and natural gas operations in 2018 were 87%/13% as compared to 2017 at 80%/20%. Production taxes, as a percentage of oil and natural gas revenues, were consistent at approximately 5% for the quarters ended March 31, 2018 and 2017. Over the same period, our per Boe commodity prices (excluding the effects of derivatives) increased 33%.

Exploration costs. Exploration costs were $5 thousand for the three months ended March 31, 2018. Exploration costs were $3.1 million for the three months ended March 31, 2017. This 2017 amount was primarily comprised of leasehold costs of certain leases in the Permian Basin of Texas which the Partnership allowed to expire as they were determined to have no future development potential.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,			
	2018		2017	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
Depletion of proved oil and natural gas properties	$ 43,617	$ 14.82	$ 30,160	$ 15.33
Depreciation of other property and equipment	711	0.24	680	0.35
Total depletion, depreciation and amortization	$ 44,328	$ 15.06	$ 30,840	$ 15.68
Average oil price used to estimate proved oil reserves at period end	$ 49.94		$ 44.10	
Average natural gas price used to estimate proved natural gas reserves at period end	$ 3.00		$ 2.73	

Depletion of proved oil and natural gas properties was $43.6 million ($14.82 per Boe) for the three months ended March 31, 2018, an increase of $13.4 million (45%) from $30.2 million ($15.33 per Boe) for the three months ended March 31, 2017. The increase in depletion expense was primarily due to the increases in production and the increase in capitalized costs being depleted and depreciated resulting from the successful 2017 and 2018 drilling programs including the reclassification of unproved leasehold costs to proved leasehold costs as additional proved reserves are added offset by increases in proved developed producing reserves and total proved reserves. The increase in reserves is primarily due to the results of our successful horizontal well development in 2017 and 2018.

The 3% decrease in depletion expense per Boe was primarily due to the increase in proved developed producing reserves and total proved reserves of 35% and 29%, respectively, at March 31, 2018 as compared to March 31, 2017 and the increase in production from period to period.

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31, 2018			
	2018		2017	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
General and administrative expenses	$ 4,658	$ 1.58	$ 3,978	$ 2.02
Non-cash unit-based compensation	1,084	0.37	975	0.50
Total general and administrative expenses	$ 5,742	$ 1.95	$ 4,953	$ 2.52

General and administrative expenses were approximately $5.7 million ($1.95 per Boe) for the three months ended March 31, 2018, an increase of $0.8 million (16%) from $5.0 million ($2.52 per Boe) for the three months ended March 31, 2017. The increase in general and administrative expenses is due to increases in CrownQuest's staffing, non-cash unit-based compensation and other administrative expenses resulting from the continued growth of the Partnership.

Net gains (losses) on derivatives. The following table sets forth the cash settlements and the non-cash mark-to-market adjustments for our derivative contracts for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
(in thousands)	2018	2017
Cash receipts:		
Commodity derivatives - oil	$ 8,966	$ 26,756
Mark-to-market gain (loss):		
Commodity derivatives - oil	(416)	4,720
Realized and unrealized net gain on derivatives	$ 8,550	$ 31,476

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
($ in thousands)	2018	2017
Interest expense	$ 15,484	$ 15,642
Weighted average interest rate	6.13%	8.17%
Weighted average cash interest rate	5.87%	7.71%
Weighted average debt balance	$ 1,010,136	$ 766,090

The increase in weighted average debt balance during the three months ended March 31, 2018 was due to the issuance of the 2025 Senior Notes in October 2017. The decrease in interest expense, the weighted average interest rate and the weighted average cash interest rate during the three months ended March 31, 2018 is due the lower interest rate on the 2025 Senior Notes of 5.625% as compared to the weighted average interest rate on the 2021 Senior Notes and the 2023 Senior Notes of 7.53%.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are for the development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations, distributions to Holdings and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility and proceeds from the disposition of assets or alternative financing sources, as discussed in "Capital resources" below.

Oil and natural gas properties. Our cash flows used by investing activities in our oil and natural gas properties during the three months ended March 31, 2018 and 2017 totaled $139.7 million and $81.9 million, respectively. Of these amounts, $1.6 million and $5.1 million, respectively, were used in the acquisition of proved oil and natural gas properties and undeveloped leasehold acreage in West Texas and $138.1 million and $76.8 million, respectively, were used in drilling and development. The 2018 and 2017 expenditures were funded by cash flow from operations and cash on hand.

Our capital expenditure plan for drilling and completion activities for 2018 will range from approximately $573 million to $630 million, all of which has been allocated to drilling activities in the Permian Basin. Our capital expenditure plan does not include acquisitions, outside operated projects or asset retirement obligations. In addition to our drilling and completion capital expenditures, our 2018 capital expenditure plan includes approximately $55 million for infrastructure (such as tank batteries, gathering pipelines, water sources and frac pits) in order to support our drilling activity and the resulting increase in production. We currently believe that our operating cash flows alone will not meet both our short-term working capital requirements and our current 2018 capital expenditure plans. We believe, however, that we have adequate cash on hand and availability under our credit facility to fund any cash flow deficits. Nonetheless, if we experience sustained oil and natural gas prices significantly below the current levels or substantial increases in our drilling and completion costs, we may further reduce our capital spending program to be within our cash flow.

Although we cannot provide any assurance, we generally attempt to fund our non-acquisition expenditures with our available cash and operating cash flow as adjusted from time to time; however, we may also use our credit facility, or alternative financing sources, to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, timing of lease expirations, actual drilling results, the availability of drilling rigs and other services and equipment, regulatory, technological and competitive developments and market conditions. In addition, under certain circumstances we would consider increasing or reallocating our capital spending plans.

Our 2018 capital expenditure plan is exclusive of acquisitions. We do not have a specific acquisition plan, since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, exploration and control of operations that will allow us, through our operator, CrownQuest, to apply our operating expertise.

Acquisitions. Our expenditures for acquisitions of proved oil and natural gas properties and undeveloped leasehold acreage totaled approximately $1.6 million and $5.1 million for the three months ended March 31, 2018 and 2017, respectively. The acquisitions during 2018 and 2017 were comprised of several separate purchases of undeveloped leasehold acreage in West Texas.

Divestitures. We regularly review our asset base to assess the market value versus holding value of existing assets, with a view to optimizing deployed capital. While we generally do not dispose of assets solely for the purpose of reducing debt, such dispositions can have the result of furthering our objective of increasing financial flexibility through reduced debt levels. We did not make any significant asset divestitures during the three months ended March 31, 2018 and 2017.

Exchanges. If it is deemed value-adding, we will enter into exchange agreements with competitors to trade undeveloped acreage as part of our strategy to consistently pursue financially viable deals to further enhance our horizontal well drilling inventory in the Permian Basin. We consummated numerous such exchanges during 2017. We did not consummate any significant exchanges during the three months ended March 31, 2018.

Contractual obligations. In the normal course of business, we enter into various contractual obligations that affect, or could affect, our liquidity. Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, equipment purchase obligations and other obligations.

We had the following contractual obligations at March 31, 2018:

	Payments due by Period				
(in thousands)	**Total**	**2018**	**2019-2020**	**2021-2022**	**2023 and Thereafter**
Long-term debt (a)	$ 1,010,053	$ 748	$ 2,134	$ 2,351	$ 1,004,820
Cash interest expense on debt (b)	452,800	57,228	113,300	113,084	169,188
Asset retirement obligations (c)	20,962	262	1,986	426	18,288
Operating lease obligations (d)	12,664	1,771	4,273	2,586	4,034
Total	$ 1,496,479	$ 60,009	$ 121,693	$ 118,447	$ 1,196,330

(a) The amounts included in the table above represent principal maturities only.
(b) Cash interest expense on our unsecured senior notes is estimated assuming no principal repayment until their maturity dates. Also included in the "2018" column is accrued interest at March 31, 2018, for our unsecured senior notes of approximately $26.6 million.
(c) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period, net of any future accretion.
(d) Operating lease obligations are for office space. All of this lease obligation relates to the Canvasback leases, which are eliminated in consolidation.

As set forth in the First Amended and Restated Limited Liability Company Agreement of Silvertip, dated August 31, 2017, we are committed to contribute $14 million to Silvertip, of which $8.7 million has been contributed as of March 31, 2018. The remaining commitment of $5.3 million is due at the time we receive capital call notifications from Silvertip which is unknown at this time. Our capital commitment to Silvertip expires on August 31, 2020.

Off-balance sheet arrangements. Currently, we do not have any off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from operating activities, financing provided by our credit facility and fixed rate senior notes, equity investments by our partners and strategic divestitures such as the sale of our ownership interest in certain properties, the proceeds of which we used, in part, to acquire additional net acres. We currently believe that our operating cash flows alone will not meet both our short-term working capital requirements and our current 2018 capital expenditure plans. We believe, however, that we have adequate cash on hand and availability under our credit facility to fund any operating cash flow deficits.

The following table summarizes our net decrease in cash and cash equivalents for the three months ended March 31, 2018 and 2017:

(in thousands)	Three Months Ended March 31, 2018		Three Months Ended March 31, 2017	
Net cash provided by operating activities	$	100,703	$	55,843
Net cash used in investing activities		(143,205)		(77,171)
Net cash used in financing activities		(456)		(5,145)
Net decrease in cash and cash equivalents	$	(42,958)	$	(26,473)

Cash flow from operating activities. The increase in operating cash flows during the three months ended March 31, 2018 over 2017 was principally due to increases in oil and natural gas revenues offset by increases in oil and natural gas production costs.

Cash flow from investing activities. During the three months ended March 31, 2018 and 2017, we invested $139.7 million and $81.9 million, respectively, for additions to, and acquisitions of, oil and natural gas properties. During the three months ended March 31, 2018 and 2017, we also invested $1.7 million and $2.5 million, respectively, in other property and equipment. Additionally, during 2018, we invested $1.8 million in an equity investment. Cash flows used in investing activities during the three months ended March 31, 2017 were offset by $7.2 million of proceeds from sales and exchanges of oil and natural gas properties.

Cash flow from financing activities. Net cash used in financing activities of $0.5 million for the three months ended March 31, 2018 primarily consisted of repayments of borrowings under the construction loan and payments of loan costs. Net cash used in financing activities of $5.1 million for three months ended March 31, 2017 consisted of repayments of borrowings under the construction loan, payments of loan costs and payment of accrued treasury unit purchases.

We intend to make periodic tax distributions and profit distributions to Holdings in the future to the extent allowed by our credit facility and the indenture and when and if declared by our board of directors of our general partner, CrownRock, GP, LLC, and to the extent consistent with our operating plan and financial strategy.

After January 1, 2018, distributions will be made solely to Holdings as our sole limited partner. Holdings must make quarterly tax distributions to the holders of its Series A Preferred Units in cash beginning with the quarter ending March 31, 2018. The amount of such tax distributions for 2018 is expected to be approximately $22.5 million. Since Holdings' only asset is its ownership of the Partnership and the Partnership's general partner, the funds Holdings requires to pay the quarterly tax distributions will be obtained from the Partnership paying quarterly distributions to Holdings. Our credit facility and the indenture governing our 2025 Senior Notes have restrictive covenants limiting dividends and distributions. We estimate that we can pay the necessary quarterly tax distributions to Holdings within the limits of these two agreements

Our credit facility, as amended, has a maturity date of April 1, 2020. At March 31, 2018 and as of the date of this report, the elected borrowing base under our credit facility was $500 million. As of May 10, 2018, we had borrowings of $40 million outstanding against that borrowing base resulting in $460 million of available borrowing capacity. Between scheduled borrowing base redeterminations, we and, if requested by 66.67% of the lenders, the lenders, may each request one special redetermination. Our next scheduled borrowing base redetermination will occur in October 2018.

Advances on the credit facility bear interest, at our option, based on (i) the prime rate of Union Bank, N.A. ("Union Bank Prime Rate") (4.75% at March 31, 2018) or (ii) a Eurodollar rate (substantially equal to the LIBOR). The credit facility's interest rates on Eurodollar rate advances and Union Bank Prime Rate advances varied, with interest margins ranging from 250 to 350 basis points and 150 to 250 basis points, respectively, per annum depending on the debt balance outstanding. We pay commitment fees on the unused portion of the available commitment of 50 basis points per annum.

In conducting our business, we may use various financing sources, including the issuance of fixed and floating rate debt and capital contributions from Holdings. We may also sell assets. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal sources of short-term liquidity are cash on hand and available borrowing capacity under our credit facility. At March 31, 2018, we had $53.1 million of cash on hand.

At March 31, 2018, the elected borrowing base under our credit facility was $500 million, with $500 million available for borrowing. In general, redeterminations are based upon a number of factors, including commodity prices and reserve levels. Upon a redetermination, our borrowing base could be substantially reduced. There is no assurance that our borrowing base will not be reduced. As of May 10, 2018, we have borrowings of $40 million outstanding under our credit facility, with $460 million available for borrowing.

Debt ratings. We receive debt ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P's corporate rating for us is "B+" with a stable outlook. Moody's corporate rating for us is "B2" with a stable outlook. S&P and Moody's consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. Our book capitalization at March 31, 2018 was $1,982.3 million, consisting of debt of $1,010.1 million and partners' capital of $972.2 million. Our debt to book capitalization was 51.0% and 52.3% at March 31, 2018 and December 31, 2017, respectively. Our ratio of current assets to current liabilities was 2.99 to 1.00 at March 31, 2018 as compared to 9.45 to 1.00 at December 31, 2017.

Inflation and changes in prices. While the general level of inflation affects certain costs associated with the oil and natural gas industry, inflation has historically had a minimal effect on us. Our results of operations and cash flows are instead affected by changing oil and natural gas prices. Commodity prices are subject to significant fluctuations that we are unable to control or predict. During the three months ended March 31, 2018, we received an average of $63.68 per barrel of oil, $1.79 per Mcf of natural gas and $20.41 per barrel of natural gas liquids before consideration of commodity derivative contracts compared to $50.80 per barrel of oil, $2.35 per Mcf of natural gas and $16.74 per barrel of natural gas liquids during the three months ended March 31, 2017. Although commodity prices fell significantly during 2015 and 2016, the higher prices during 2017 and the first three months of 2018 have led to increased activity in the industry and, consequently, rising costs. The cost trends put pressure not only on our operating costs, but also on capital costs.

Critical Accounting Policies and Practices

There have been no material changes in our critical accounting policies during the three months ended March 31, 2018.

Quantitative and Qualitative Disclosure About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at March 31, 2018, and from which we may incur future gains or losses from changes in market commodity prices. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which CrownQuest markets to energy marketing companies and refineries and to a lesser extent our derivative counterparties.

We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness. We currently require one counterparty to whom we sell our oil and natural gas production to provide collateral support for their obligation to us. We also require another production sales counterparty to route payment through a large financial firm with substantial credit capability. We may, if circumstances dictate, require additional collateral or payment terms in the future.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. At March 31, 2018, the fair value of our financial derivatives is a net asset of $57.4 million. All of our counterparties to these financial derivatives are parties or affiliates of parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party or its affiliates. See Note I of the Notes to Consolidated Financial Statements included in "Financial Statements and Supplementary Data" for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of oil and natural gas we have entered into, and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing net income. The fair value of our oil swap agreements at March 31, 2018 was a net asset of $57.4 million. A 10% increase (decrease) in oil prices with all other factors held constant would result in a decrease (increase) in the fair value (generally correlated to our estimated future net cash flows from such instruments) of our oil commodity contracts of approximately $41.1 million.

Pursuant to our current risk management approach, we seek to enter into derivative contracts to cover a portion of the oil volumes expected to be produced within five years from the proved properties included in the borrowing base under our revolving credit facility.

The following table lists the percentage of our projected oil production from proved properties covered by fixed price swap agreements and the weighted average swap prices at March 31, 2018:

	Projected Proved Production Covered (a)	Weighted Average Swap Prices	
	Crude Oil	Crude Oil	
Remainder of 2018	79%	$	68.15
2019	8%	$	60.45

(a) Based on the internally-prepared reserve evaluation effective April 1, 2018 utilizing oil price of $49.94

Our actual production may materially vary from the amounts estimated in the April 1, 2018 reserve report.

The fair value of our commodity derivative instruments is determined based on our valuations models. We did not change our valuation method during 2018. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the three months ended March 31, 2018:

(in thousands)	Derivative Instruments Net Assets (Liabilities) (a) Commodities	
Fair value of contracts outstanding at December 31, 2017	$	57,803
Changes in fair values (b)		8,550
Contract maturities		(8,966)
Fair value of contracts outstanding at March 31, 2018	$	57,387

(a) Represents the fair values of open derivative contracts subject to market risk.

(b) At inception, new derivative contracts entered into by us have no intrinsic value.

Interest rate risk. Our exposure to changes in interest rates relates primarily to our debt obligations, including our revolving credit facility, which requires us to pay higher interest rate margins as we use a larger percentage of our available commitments. We manage our exposure to changes in interest rates by limiting our variable-rate debt obligations to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates, we may use interest rate derivatives. We would not use interest rate derivatives to modify the overall leverage of our debt portfolio.

OTHER INFORMATION

Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceedings. In addition, we are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

Risk Factors

In addition to the other information set forth in this Quarterly Report, see information under the heading "Risk Factors" in our Annual Report to Holders of 5.625% Senior Notes due 2025 for the Fiscal Year Ended December 31, 2017, filed with the trustee on March 9, 2018. There have been no material changes to the risk factors disclosed in the Annual Report.

Exhibits

Not applicable

SIGNATURES

CrownRock, L.P. has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on May 10, 2018.

CrownRock, L.P.

By: CrownRock, GP, LLC, its general partner

By: /s/ Timothy M. Dunn
Timothy M. Dunn
Chief Executive Officer

By: /s/ Charles W. Wetzel
Charles W. Wetzel
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)