Quarterly Report to Holders of 5.625% Senior Notes due 2025
For the quarterly period ended June 30, 2019

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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)

	June 30, 2019	December 31, 2018
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 63,902	$ 74,153
Accounts receivable – related party:		
Oil and natural gas	62,144	55,061
Other	29,839	17,234
Prepaid costs and other current assets	6,210	13,359
Derivative instruments	53,936	176,281
Total current assets	216,031	336,088
Oil and natural gas properties, net, successful efforts method of accounting	2,416,524	2,161,129
Other property and equipment, net	100,504	93,051
Deferred loan costs, net	5,161	1,489
Noncurrent derivative instruments	14,158	74,470
Other assets	11,345	9,379
Total Assets	$ 2,763,723	$ 2,675,606
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accrued drilling cost – related party	$ 67,286	$ 34,740
Other accrued liabilities – related party	15,837	10,534
Accrued interest payable	14,262	14,072
Current portion of long-term debt	1,066	1,042
Other current liabilities	4	1,220
Asset retirement obligations, current portion	197	265
Total current liabilities	98,652	61,873
Long-term debt, net	1,292,761	1,177,154
Asset retirement obligations	24,562	23,321
Total liabilities	1,415,975	1,262,348
Commitments and Contingencies (Note J)		
CrownRock, L.P. Partners' Capital	1,347,794	1,413,296
Non-controlling interest in subsidiary	(46)	(38)
Total Partners' Capital	1,347,748	1,413,258
Total Liabilities and Partners' Capital	$ 2,763,723	$ 2,675,606

See accompanying notes to these unaudited consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)		(In thousands)	
Statements of Operations				
Revenues and gain (loss):				
Oil and natural gas sales	$ 201,344	$ 142,435	$ 383,257	$ 279,859
Gain (loss) on exchange of oil and natural gas properties	-	63,253	(84)	63,253
Rent - gathering system	1,234	564	2,498	1,041
Transportation fees and saltwater disposal	5,421	3,885	9,995	6,969
Surface ownership	177	659	741	993
Fresh water supply	2,542	1,732	5,511	2,714
Total revenues and gain (loss)	210,718	212,528	401,918	354,829
Costs and expenses:				
Lease operating expense	33,910	22,340	65,648	42,963
Production and ad valorem taxes	12,918	7,778	23,097	15,850
Exploration costs	406	2,254	1,241	2,259
Depreciation, depletion and amortization	86,736	48,351	155,852	92,679
Impairment of oil and natural gas properties	589	745	1,282	1,391
Accretion of discount on asset retirement obligation	281	238	552	468
General and administrative	6,101	6,264	12,331	12,005
Total costs and expenses	140,941	87,970	260,003	167,615
Operating income	69,777	124,558	141,915	187,214
Other income (expense):				
Gain (loss) on derivatives not designated as hedges	38,170	(14,747)	(157,843)	(6,197)
Interest income	224	90	329	173
Interest expense	(19,162)	(17,021)	(37,452)	(32,505)
Other income (expense), net	1,150	235	1,723	246
Total other income (expense)	20,382	(31,443)	(193,243)	(38,283)
Net income (loss)	90,159	93,115	(51,328)	148,931
Net loss attributable to non-controlling interest	2	28	8	58
Net income (loss) attributable to CrownRock, L.P.	$ 90,161	$ 93,143	$ (51,320)	$ 148,989
Statements of Comprehensive Income (Loss)				
Net income (loss)	$ 90,159	$ 93,115	$ (51,328)	$ 148,931
Less: Comprehensive loss attributable to the non-controlling interest	2	28	8	58
Comprehensive income (loss) attributable to CrownRock, L.P.	$ 90,161	$ 93,143	$ (51,320)	$ 148,989

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			
Balance, January 1, 2018	-	$ -	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)	-	516,947	-	-	-	-	-	-	-	-	-	-	-	-	516,947	(493)	516,454
Distribution to limited partner	-	(28,035)	-	-	-	-	-	-	-	-	-	-	-	-	(28,035)	-	(28,035)
Capital contribution - unit based compensation	-	4,381	-	-	-	-	-	-	-	-	-	-	-	-	4,381	-	4,381
Voided treasury unit purchase																	
Class D units	-	12	-	-	-	-	-	-	-	-	-	-	-	-	12	-	12
Balance, December 31, 2018	100	$ 1,413,296	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	$ 1,413,296	$ (38)	$ 1,413,258
Net loss	-	(51,320)	-	-	-	-	-	-	-	-	-	-	-	-	(51,320)	(8)	(51,328)
Distribution to limited partner	-	(16,107)	-	-	-	-	-	-	-	-	-	-	-	-	(16,107)	-	(16,107)
Capital contribution - unit based compensation	-	1,925	-	-	-	-	-	-	-	-	-	-	-	-	1,925	-	1,925
Balance, June 30, 2019	100	$ 1,347,794	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	$ 1,347,794	$ (46)	$ 1,347,748

See accompanying notes to these unaudited consolidated financial statements.

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

	Six Months Ended June 30, 2019	Six Months Ended June 30, 2018
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (51,328)	$ 148,931
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	155,852	92,679
Accretion of discount on asset retirement obligation	552	468
Accretion of discount on long-term debt	183	38
Amortization of deferred loan costs	1,532	1,389
Unit-based compensation expense	1,925	2,199
Exploration costs	1,241	2,259
Settlements of asset retirement obligations	(242)	(35)
Impairment of oil and natural gas properties and facilities	1,282	1,391
Loss on derivative instruments	182,657	21,637
(Gain) loss on exchanges of oil and natural gas properties	84	(63,253)
Income on equity method investments	(1,966)	(236)
Change in assets and liabilities:		
Accounts receivable – related party	(19,688)	(20,186)
Prepaid costs and other current assets	7,148	2,059
Accounts payable - related party	-	(98)
Other accrued liabilities - related party	5,224	(1,269)
Accrued interest payable	190	1,572
Other liabilities	(1,216)	(750)
Net cash flows provided by operating activities	283,430	188,795
Cash flows from investing activities:		
Acquisition of leasehold and oil and natural gas properties	(7,158)	(4,564)
Capital expenditures on oil and natural gas properties	(372,633)	(289,793)
Additions to other property and equipment	(8,106)	(2,125)
Contributions to equity method investments	-	(1,782)
Net cash flows used in investing activities	(387,897)	(298,264)
Cash flows from financing activities:		
Distributions to partners	(16,028)	(5,171)
Proceeds from issuance of 5.625% Senior Notes due 2025	-	181,781
Repayments of long-term borrowings under construction loan	(515)	(491)
Proceeds from long-term borrowings under credit facility	170,000	55,000
Repayments of long-term borrowings under credit facility	(55,000)	(55,000)
Payments for loan and debt issue costs	(4,241)	(2,644)
Purchase of treasury units	-	(17)
Net cash flows provided by financing activities	94,216	173,458
Net increase (decrease) in cash, cash equivalents and restricted cash	(10,251)	63,989
Cash, cash equivalents and restricted cash, beginning of period	74,153	96,067
Cash, cash equivalents and restricted cash, end of period	$ 63,902	$ 160,056
Supplemental disclosure of cash flow information:		
Cash paid for interest	$ 35,982	$ 30,576
Non-cash investing and financing activities:		
Change in accrued capital expenditures in accrued drilling cost and accrued liabilities	32,546	31,300
Additions to asset retirement obligation	882	909
Asset retirement obligation associated with properties exchanged or sold	(19)	(48)
Change in accrued loan origination costs	-	79
Change in accrued distribution to limited partner	79	6,126
Change in accrued treasury unit purchases	-	(29)

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 $1.185 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 two field operations offices in Martin County, Texas.

Interim financial statements. These consolidated financial statements as of June 30, 2019 and for the three and six months ended June 30, 2019 and 2018 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, 2018.

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)**

Restricted cash. Restricted cash represents proceeds from the sale of certain oil and natural gas properties that the Partnership deposited with a qualified intermediary to facilitate like-kind oil and natural gas property acquisition transactions pursuant to Section 1031 of the Internal Revenue Code. This arrangement and the restrictions on the cash in the deposit account expired on April 29, 2019 and the remaining balance of $7.8 million was transferred to the Partnership's operating account.

The following table provides the components of cash, cash equivalents and restricted cash as presented on the condensed consolidated balance sheets.

	June 30, 2019		December 31, 2018	
	(In thousands)			
Cash and cash equivalents	$	63,902	$	64,005
Restricted cash		-		10,148
Total cash, cash equivalents and restricted cash	$	63,902	$	74,153

Accounts receivable and allowance for doubtful accounts. CrownQuest markets most of 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 and support infrastructure, including water-related wells, facilities and equipment, net of estimated salvage values, are depleted and depreciated by the units-of-production method. Acquisition and leasehold costs of proved properties are depleted on the basis of total proved reserves, and capitalized development costs (wells and related equipment and facilities) are depreciated 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 – Nonmonetary transactions.

B. Summary of Significant Accounting Policies (Continued)

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.

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 June 30, 2019 was as follows:

In thousands		
Remaining 2019	$	1,527
2020		3,053
2021		3,053
2022		3,053
2023		3,053
Thereafter		3,564
Total	$	17,303

B. Summary of Significant Accounting Policies (Continued)

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. Through June 30, 2019, the Partnership has contributed $8.7 million in cash 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 31% 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 six months ended June 30, 2019, CrownRock recognized income of $2.0 million associated with its share of the net income of Silvertip. During the six months ended June 30, 2018, CrownRock recognized income of $236 thousand associated with its share of the net income of Silvertip. The income and loss is included in Other income (expense), net in the consolidated statements of operations. 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:

> ***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.
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> ***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.

B. Summary of Significant Accounting Policies (Continued)

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).

Accounting pronouncements being adopted in 2019. The Partnership is adopting ASU No. 2014-09, Accounting Standards Codification ("ASC") 606, "Revenue from Contracts with Customers" ("ASC 606"), which supersedes the revenue recognition requirements in ASC 605, "Revenue Recognition" ("ASC 605"), in 2019 using the modified retrospective transition method. Results for annual reporting periods beginning after January 1, 2019, and for quarterly reporting periods beginning after January 1, 2020 will be presented under ASC 606, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting under ASC 605. The Partnership completed a detailed review of its revenue contracts in 2018, which represented all of the Partnership's significant revenue streams including oil, natural gas and NGL sales, in order to adopt the new standard beginning in 2019. The Partnership does not expect to record a change to its opening partners' capital as of January 1, 2019 as no material change is expected to the timing or pattern of revenue recognition due to the adoption of ASC 606.

The adoption is not expected to have a material impact on the Partnership's reported net income (loss), cash flows from operations or statement of partners' capital for fiscal year 2019. Full presentation of the impact of the adoption of ASC 606 and the related disclosures will be included in the Partnership's financial statements for the year ended December 31, 2019.

New accounting pronouncements issued but not yet adopted. In August 2018, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") No. 2018-13, "Fair Value Measurement (Topic 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement", as part of the FASB's disclosure framework project to improve the effectiveness of disclosures in the notes to the financial statements. These amendments modify the disclosure requirements in Topic 820 by removing certain disclosures, modifying certain existing disclosures, and adding new disclosures. The amendments in this update apply to all entities that are required under existing generally accepted accounting principles ("GAAP") to make disclosures about recurring or nonrecurring fair value measurements. Certain of the disclosures that are required by the amendments in this update are not required for nonpublic entities. This new guidance is effective for the Partnership for fiscal years beginning after December 15, 2019. An entity is permitted to early adopt any removed or modified disclosures upon issuance of ASU No. 2018-13 and delay adoption of the additional disclosures until their effective date. The Partnership is currently evaluating the impact of ASU No. 2018-13 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. However, at its meeting on July 17, 2019, the FASB Board decided to delay the effective date of Topic 842 for private companies for an additional year with a proposed effective date of fiscal periods beginning after December 15, 2020, and interim periods within fiscal years beginning after December 15, 2021. The FASB Board directed the FASB staff to draft a proposed ASU to be voted on at a later date. The comment period for the proposed ASU will be 30 days. 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 January 2018, the FASB issued ASU No. 2018-01, "Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842", which provides an optional practical expedient to not evaluate land easements that existed or expired before the adoption of ASU 2016-02 and that were not previously accounted for as leases under the original "Leases (Topic 840)" accounting standard. Since the Partnership has not yet adopted ASU No. 2016-02, this new guidance is effective for the Partnership at the same effective date of ASU No. 2016-02. The Partnership is currently evaluating the impact of ASU No. 2018-01 on its consolidated financial statements.

In July 2018, the FASB issued ASU No. 2018-11, "Leases (Topic 842): Targeted Improvements". These amendments provide entities with an additional (and optional) transition method to adopt the new leases standard (ASU No. 2016-02). Entities currently are required to adopt the new leases standard using a modified retrospective transition method. Under the new transition method provided by ASU No. 2018-11, an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements in which it adopts the new leases standard will continue to be in accordance with current GAAP (Topic 840, Leases). ASU 2018-11 also provides lessors with a practical expedient, by class of underlying asset, to not separate nonlease components from the associated lease component and, instead, to account for those components as a single component if the nonlease components otherwise would be accounted for under the new revenue guidance (Topic 606) and certain criteria are met. The amendments in this update related to transition relief on comparative reporting at adoption affect all entities with lease contracts that choose the additional transition method, while the amendments in this update related to separating components of a contract affect only lessors whose lease contracts qualify for the practical expedient. Since the Partnership has not yet adopted ASU No. 2016-02, this new guidance is effective for the Partnership at the same effective date of ASU No. 2016-02. The Partnership is currently evaluating the impact of ASU No. 2018-11 on its consolidated financial statements.

Subsequent events. The Partnership performed an evaluation of subsequent events through August 9, 2019, 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 June 30, 2019 and December 31, 2018:

	June 30, 2019	December 31, 2018
	(In thousands)	
Proved oil and natural gas properties	$ 3,037,025	$ 2,661,716
Unproved oil and natural gas properties	351,560	320,972
Less accumulated depreciation, depletion, amortization and impairment	(972,061)	(821,559)
Net oil and natural gas properties	$ 2,416,524	$ 2,161,129

During the three and six months ended June 30, 2019, the Partnership recognized exploration costs of approximately \$0.4 million and \$1.2 million, respectively, primarily comprised of dry hole expense on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas. During the three months ended June 30, 2018, the Partnership recognized exploration costs of approximately \$2.3 million comprised of dry hole expense of two oil and natural gas wells on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas. During the six months ended June 30, 2018, the Partnership recognized exploration costs of approximately \$2.3 million comprised of approximately \$2.3 million of dry hole expense and \$5 thousand related to geological and geophysical costs.

C. Oil and Natural Gas Properties (Continued)

During the three and six months ended June 30, 2019, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of approximately \$0.6 million and \$1.3 million, respectively, to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire. Lease expirations in the amount of \$1.9 million were written off to the allowance during 2019 and the remaining allowance at June 30, 2019 was \$1.0 million. During the three and six months ended June 30, 2018, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of approximately \$0.7 million and \$1.4 million, respectively, to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire.

See Note I – Fair Value for discussion of proved property impairments. No proved property impairments were recorded during the three and six months ended June 30, 2019 and 2018.

The Partnership initiated a horizontal well drilling program in January 2015. The Partnership capitalizes horizontal and vertical well costs as exploratory 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 producing reserves at June 30, 2019 were \$56.7 million. All of these costs are from wells drilled during the six months ended June 30, 2019.

D. Other Property and Equipment

The following table sets forth the Partnership's other property and equipment as of June 30, 2019 and December 31, 2018:

	June 30, 2019	December 31, 2018
	(In thousands)	
Land	$ 24,149	$ 24,149
Water rights	11,872	11,872
Construction in progress - gathering systems	8,852	815
Office buildings	26,050	26,050
Equipment	91	56
Gathering systems	42,555	40,719
Abajo Pipeline and gathering facilities	11,714	11,714
Less accumulated depletion, depreciation and impairment	(24,779)	(22,324)
Net other property and equipment	$ 100,504	$ 93,051

Land and water rights. The Partnership owns surface acreage located in various portions of the Partnership's core northern Midland Basin leasehold acreage. The Partnership's purchase of surface acreage is part of its ongoing strategy to cost-effectively support its horizontal drilling program in the Midland Basin. The Partnership also owns the water rights attached to certain portions of the surface acreage. The ownership of these water rights allows 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. In July 2018, the Partnership began depleting its capitalized water rights using the units-of-production method on the basis of estimated water reserves. During the three and six months ended June 30, 2019, \$0.4 million and \$1.0 million, respectively, were recorded to depletion expense.

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 field operations office and a 15,140 square feet extension of the field operations office in Martin County, Texas.

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 60,000 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 28 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 90,000 barrels per day of produced liquids. The three systems contain approximately 158 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 and six months ended June 30, 2019 and 2018:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)		(In thousands)	
Balance, beginning of period	$ 24,326	$ 20,962	$ 23,586	$ 20,231
Liabilities incurred during the period	246	398	882	909
Liabilities settled during the period	(75)	(25)	(242)	(35)
Liabilities associated with properties exchanged	(19)	(48)	(19)	(48)
Accretion expense	281	238	552	468
Balance, end of period	24,759	21,525	24,759	21,525
Less current portion	(197)	(265)	(197)	(265)
Non-current portion	$ 24,562	$ 21,260	$ 24,562	$ 21,260

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 June 30, 2019 approximated $63.3 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 June 30, 2019, the Partnership has a net derivative asset of $68.1 million, a portion of 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 June 30, 2019, and December 31, 2018, 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 $76.4 million and $38.7 million, respectively, related specifically to accrued drilling costs on wells being drilled and completed as of period end, accrued lease operating expenses and management fees. Further, with respect to the properties operated by CrownQuest, at June 30, 2019 and December 31, 2018, related party accounts receivable outstanding in the normal course of business related primarily to accrued oil and natural gas sales, fresh water sales and water disposal fees were $92.0 million and $72.3 million, respectively.

As a result of its ownership of surface acreage, water rights and infrastructure, the Partnership recognizes amounts due from CrownQuest for surface damages, fresh water purchases and water disposal. During the six months ended June 30, 2019 and 2018, the Partnership recognized receivables from CrownQuest of $5.6 million and $3.4 million, respectively, for these transactions. These amounts due are included in the related party accounts receivable listed above.

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. During the three and six months ended June 30, 2019, the Partnership recorded management fees of $5.1 million and $10.3 million, respectively, in general and administrative expenses. During the three and six months ended June 30, 2018, the Partnership recorded management fees of $4.9 million and $9.6 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 six months ended June 30, 2019 and 2018, payments of $18.6 million and $14.3 million, respectively, were made by CrownQuest to affiliates for royalty interests, lease bonuses and extensions, surface acquisitions, surface damages, water purchases and water disposal with respect to such properties. Payments during the six months ended June 30, 2019 include amounts paid to a CrownQuest-affiliated royalty company formed in July 2018 (the "2018 Royalty Company"). Payments during the six months ended June 30, 2019 and 2018 include amounts paid to a CrownQuest-affiliated royalty company formed in March 2016 (the "2016 Royalty Company"). These royalty companies acquired royalty interests from third parties on properties operated by CrownQuest and in which the Partnership owns working interests. Payments to the 2018 Royalty Company and the 2016 Royalty Company during the six months ended June 30, 2019 were $207 thousand and $15.5 million, respectively, primarily for royalty interests on properties operated by CrownQuest and in which the Partnership owns working interests. Payments to the 2016 Royalty Company during the six months ended June 30, 2018 were $9.7 million for royalty interests.

G. Related Party Transactions (Continued)

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 ultimate general partner, CrownRock GP, LLC, and his wife has royalty interests in certain properties that the Partnership is developing in the Permian Basin. During the six months ended June 30, 2019 and 2018, CrownQuest paid $11 thousand and $3 thousand, respectively, for royalty interests.

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 six months ended June 30, 2019, CrownQuest paid $5.2 million for royalty interests, surface damages and water purchases. During the six months ended June 30, 2018, the Partnership paid $2.3 million 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. The final payment of $555,000 was paid in January 2019.

Related party owner and operator of aircraft used by CrownQuest. Mr. Floyd and EnerQuest Oil & Gas Ltd. ("EOG"), an entity affiliated with the Partnership, own an entity named EnerQuest Aviation Partners, LLC ("Aviation Partners") which owns 60% of an aircraft with the other 40% belonging to a third party individual. The aircraft is managed by Crown Eye Partners, LLC ("Crown Eye") which is owned 60% by Aviation Partners and 40% 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 six months ended June 30, 2019, CrownQuest paid Crown Eye $45.3 thousand for usage of the aircraft for 12.6 hours at an average cost of $3,598 per hour. During the six months ended June 30, 2018, CrownQuest paid Crown Eye $59.4 thousand for usage of the aircraft for 21.5 hours at an average cost of $2,762 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 six months ended June 30, 2019 and 2018, Silvertip billed CrownQuest $16.1 million and $8.6 million, respectively, for services provided on Partnership-owned properties. The Partnership has eliminated all intra-entity income and losses related to these services.

H. Derivative Financial Instruments

The Partnership has entered into derivative contracts with counterparties 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 June 30, 2019. The following table sets forth the Partnership's outstanding commodity derivative contracts, by quarter of settlement, at June 30, 2019. When aggregating multiple contracts, the weighted average contract price is disclosed.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2019:					
Volume (Bbl)			2,944,000	2,944,000	5,888,000
Price per Bbl			$ 62.26	$ 62.52	$ 62.39
2020:					
Volume (Bbl)	2,538,900	2,730,000	2,318,400	736,000	8,323,300
Price per Bbl	$ 66.33	$ 63.68	$ 62.09	$ 65.05	$ 64.17
Oil Basis Swaps: (b)					
2019:					
Volume (Bbl)			2,944,000	2,944,000	5,888,000
Price per Bbl			$ (1.00)	$ (1.00)	$ (1.00)
2020:					
Volume (Bbl)	2,275,000	2,275,000	2,760,000	2,760,000	10,070,000
Price per Bbl	$ (0.62)	$ (0.62)	$ (0.67)	$ (0.67)	$ (0.65)

(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:

	Six Months Ended June 30,		Year Ended December 31,
	2019	2018	2018
	(In thousands)		(In thousands)
Net asset, beginning of period	$ 250,751	$ 57,803	$ 57,803
Cash settlement receipts	(24,814)	(15,440)	(36,919)
Changes in fair value of derivatives	(157,843)	(6,197)	229,867
Net asset end of period	68,094	36,166	250,751
Less current asset	53,936	22,338	176,281
Non-current asset	$ 14,158	$ 13,828	$ 74,470

H. Derivative Financial Instruments (Continued)

The Partnership's 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):

	Six Months Ended June 30, 2019		
	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 and basis derivatives	$ 90,065	$ (21,971)	$ 68,094
Liability Derivatives:			
Commodity price and basis derivatives	$ (21,971)	$ 21,971	$ -

	Year Ended December 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 and basis derivatives	$ 260,043	$ (9,292)	$ 250,751
Liability Derivatives:			
Commodity price and basis derivatives	$ (9,292)	$ 9,292	$ -

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 June 30, 2019 and December 31, 2018:

	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	$ -	$ 68,094	**$ -**	$ 68,094
Total as of June 30, 2019	$ -	$ 68,094	$ -	$ 68,094
Oil and oil basis swaps	$ -	$ 250,751	$ -	$ 250,751
Total as of December 31, 2018	$ -	$ 250,751	$ -	$ 250,751

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 June 30, 2019 and December 31, 2018:

	June 30, 2019		December 31, 2018	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In thousands)			
Assets:				
Derivative instruments	$ 68,094	$ 68,094	$ 250,751	$ 250,751

Cash, cash equivalents and restricted cash, 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 $1.2 billion at June 30, 2019. 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 and commodity price 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 and six months ended June 30, 2019, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of $0.6 million and $1.3 million, respectively, to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire. Lease expirations in the amount of $1.9 million were written off to the allowance during 2019 and the remaining allowance at June 30, 2019 is $1.0 million. During the three and six months ended June 30, 2018, the Partnership recognized a non-cash charge against earnings and a corresponding allowance for expiring acreage of $0.7 million and $1.4 million, respectively, to provide an estimated allowance related to unproved oil and natural gas leases which the Partnership may allow to expire.

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 June 30, 2019, 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.

During the six months ended June 30, 2019 and 2018, the Partnership reimbursed CrownQuest for rent expense for office space of $1.2 million, each period, 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 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 June 30, 2019 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.

After January 1, 2018, distributions are being 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. On April 13, 2018, Holdings issued 35,000 Series A Preferred Units to investors for a purchase price of $1,000 per Preferred Unit. Additionally, on May 15, 2018, Holdings issued 40,000 Series A Preferred Units for a purchase price of $1,000 per Preferred Unit. Holdings must make quarterly tax distributions in cash to the holders of its Series A Preferred Units. The amount of such tax distributions for 2019 is expected to be approximately $28.0 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.

K. Partners' Capital (Continued)

To provide Holdings with funds required to make its quarterly tax distribution, the Partnership distributed $13.2 million during the six months ended June 30, 2019 to Holdings. 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.

During the six months ended June 30, 2019, the Partnership distributed $2.8 million to Holdings for funds required to repurchase units from unitholders.

Based upon the provisions of the indenture governing the Partnership's senior notes, as of June 30, 2019, the Partnership is allowed to make distributions to Holdings of approximately $341.8 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 base salary. The Partnership's contributions to the plan, through its reimbursement to CrownQuest pursuant to the terms of an administrative support agreement, were approximately $670 thousand and $538 thousand for the six months ended June 30, 2019 and 2018, 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 six months ended June 30, 2019 and 2018, Holdings' general partner approved aggregate grants of 8,000 and 54,500, respectively, 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 six months ended June 30, 2019 or 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 ASC 718 – Compensation – Stock Compensation, no incremental compensation cost was recognized.

L. Incentive Plans

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 Holdings' restricted unit awards, comprised of Class D LP Units and Class E LP Units, for the six months ended June 30, 2019 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, 2018	481,400	$ 56.43	126,500	$ 60.59
Units granted	-	-	8,000	32.93
Units canceled/forfeited	(2,976)	65.30	-	-
Outstanding at June 30, 2019	478,424	$ 56.37	134,500	$ 58.94

The following table summarizes information about unit-based compensation for restricted unit awards, recorded in the Partnership's consolidated financial statements, for the three and six months ended June 30, 2019 and 2018:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(in thousands)	**2019**	**2018**	**2019**	**2018**
Grant date fair value for awards during the period:				
Employee grants	$ -	$ 1,437	$ 263	$ 3,192
Officer grants	-	-	-	-
Total	$ -	$ 1,437	$ 263	$ 3,192
Unit-based compensation expense from restricted units:				
Employee grants	$ 911	$ 910	$ 1,829	$ 1,788
Officer grants	50	205	96	411
Total	$ 961	$ 1,115	$ 1,925	$ 2,199

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 June 30, 2019. This cost is expected to be recognized over a weighted-average period of approximately 4.7 years.

(in thousands)	Future Compensation
Remainder 2019	$ 1,886
2020	3,251
2021	2,686
2022	2,157
2023	1,639
Thereafter	1,588
Total	$ 13,207

M. Long-term Debt

The Partnership's debt consists of the following at June 30, 2019 and December 31, 2018:

	June 30, 2019	December 31, 2018
	(In thousands)	
Credit Facility	$ 115,000	$ -
5.625% unsecured senior notes due 2025	1,185,000	1,185,000
Unamortized original issue discount	(2,821)	(3,004)
Unamortized deferred loan costs - senior notes	(11,981)	(12,933)
Construction loan - Canvasback office building	8,790	9,305
Unamortized deferred loan costs - construction loan	(161)	(172)
Total debt	1,293,827	1,178,196
Less current portion	(1,066)	(1,042)
Long-term debt	$ 1,292,761	$ 1,177,154

Credit facility. The Partnership's credit facility, as amended, (the "Credit Facility"), has a maturity date of February 8, 2024. In conjunction with its regular semiannual borrowing base redetermination, effective February 8, 2019, the Partnership elected a commitment amount of $600 million after being offered a borrowing base of $850 million by the lenders. Commitments from the Partnership's bank group total $2.0 billion. At June 30, 2019, the Partnership had no letters of credit outstanding under the Credit Facility. At December 31, 2018, 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) Eurodollar rate (substantially equal to the London Interbank Offered Rate) or (ii) the prime rate as quoted by *The Wall Street Journal* ("Prime Rate") (5.50% at June 30, 2019). The Credit Facility's interest rates on Eurodollar rate advances and Prime Rate advances vary, with interest margins ranging from 150 to 250 basis points and 50 to 150 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 37.5 to 50 basis points per annum depending on the debt balance outstanding.

M. Long-term Debt (Continued)

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.

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 within 30 days, 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 six-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 to be not less than 1.0 to 1.0, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations and including all letter of credit obligations as liabilities but excluding current maturities of indebtedness, and including any unused availability under the Credit Facility as a current asset, and
    (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 4.0 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 85% 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 3.25 to 1.00 calculated on a pro forma basis after giving effect to such cash payment.

At June 30, 2019, the Partnership was in compliance with all of the covenants under the Credit Facility.

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"). On May 22, 2018, the Partnership and CrownRock Finance issued an additional $185 million aggregate principal amount of 2025 Senior Notes at 98.26% of par. These additional notes were fungible with the original notes and are governed by the same indenture and thus contain the same terms and conditions.

The 2025 Senior Notes mature on October 15, 2025, and interest is paid in arrears semiannually on April 15 and October 15. 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%.

M. Long-term Debt (Continued)

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 ("Senior Note Indenture") contains various restrictive covenants which include:

- 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 Senior Note Indenture 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 from July 1, 2017 to the end of the Partnership's most recently ended fiscal quarter.

At June 30, 2019, 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.

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 2024. The 2025 Senior Notes are due in 2025.

Interest expense. The following amounts have been incurred and charged to interest expense for the three and six months ended June 30, 2019 and 2018:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
	(In thousands)		(In thousands)	
Cash payments for interest	$ 34,949	$ 29,823	$ 35,982	$ 30,576
Amortization of original issue discount	92	38	183	38
Amortization of deferred loan costs	763	720	1,532	1,389
Net changes in accrued interest expense	(16,642)	(13,560)	(245)	502
Total interest expense	$ 19,162	$ 17,021	$ 37,452	$ 32,505

N. Nonmonetary transactions

If it is deemed value-adding, the Partnership will enter into exchange agreements with third parties to exchange proved and unproved oil and natural gas properties as part of its strategy to consistently pursue financially viable deals to further block-up its acreage and thereby enhance its horizontal well drilling inventory in the Permian Basin.

During the six months ended June 30, 2019, the Partnership completed multiple nonmonetary transactions. These transactions included the exchange of both proved and unproved oil and natural gas properties. One of these transactions was accounted for at fair value and, as a result the Partnership recorded a loss of approximately $84 thousand.

O. Supplemental Guarantor Information

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 June 30, 2019 and December 31, 2018 and Condensed Consolidating Statements of Operations for the three and six months ended June 30, 2019 and 2018 and Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2019 and 2018, 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)

Condensed Balance Sheet	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
	As of June 30, 2019						
				(In thousands)			
Assets							
Cash and cash equivalents	$ 63,485	$ 21	$ -	$ 301	$ 95	$ -	$ 63,902
Accounts receivable – related party	91,952	214	-	-	7	(190)	91,983
Other current assets	6,106	99	-	-	5	-	6,210
Derivative instruments	53,936	-	-	-	-	-	53,936
Oil and natural gas properties	2,414,821	1,703	-	-	-	-	2,416,524
Other property and equipment	76,064	-	-	24,440	-	-	100,504
Deferred loan costs	5,161	-	-	-	-	-	5,161
Noncurrent derivative instruments	14,158	-	-	-	-	-	14,158
Other assets	11,302	43	-	-	-	-	11,345
Investment in Abajo, LLC	(40)	-	-	-	-	40	-
Investment in Canvasback Properties, LLC	16,112	-	-	-	-	(16,112)	-
Investment in Roddy, LLC	1,011	-	-	-	-	(1,011)	-
Total Assets	**$ 2,754,068**	**$ 2,080**	**$ -**	**$ 24,741**	**$ 107**	**$ (17,273)**	**$ 2,763,723**
Liabilities and Partners' Capital							
Accounts payable & accrued liabilites - related party	$ 83,099	$ 21	$ -	$ -	$ 193	$ (190)	$ 83,123
Accrued interest payable	14,262	-	-	-	-	-	14,262
Current portion of long-term debt	-	-	-	1,066	-	-	1,066
Other current liabilities	171	30	-	-	-	-	201
Long-term debt	1,285,198	-	-	7,563	-	-	1,292,761
Asset retirement obligations	23,544	1,018	-	-	-	-	24,562
Total liabilities	**$ 1,406,274**	**$ 1,069**	**$ -**	**$ 8,629**	**$ 193**	**$ (190)**	**$ 1,415,975**
CrownRock, L.P. Partners' Capital	1,347,794	1,011	-	16,112	(86)	(17,037)	1,347,794
Non-controlling interest in subsidiary	-	-	-	-	-	(46)	(46)
Total Liabilities and Partners' Capital	**$ 2,754,068**	**$ 2,080**	**$ -**	**$ 24,741**	**$ 107**	**$ (17,273)**	**$ 2,763,723**

Condensed Balance Sheet	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
	As of December 31, 2018						
				(In thousands)			
Assets							
Cash and cash equivalents	$ 73,680	$ 166	$ -	$ 214	$ 93	$ -	$ 74,153
Accounts receivable – related party	72,252	223	-	-	10	(190)	72,295
Other current assets	13,240	99	-	-	20	-	13,359
Derivative instruments	176,281	-	-	-	-	-	176,281
Oil and natural gas properties	2,159,388	1,741	-	-	-	-	2,161,129
Other property and equipment	68,240	-	-	24,811	-	-	93,051
Deferred loan costs	1,489	-	-	-	-	-	1,489
Noncurrent derivative instruments	74,470	-	-	-	-	-	74,470
Other assets	9,336	43	-	-	-	-	9,379
Investment in Abajo, LLC	(32)	-	-	-	-	32	-
Investment in Canvasback Properties, LLC	15,892	-	-	-	-	(15,892)	-
Investment in Roddy, LLC	1,235	-	-	-	-	(1,235)	-
Total Assets	**$ 2,665,471**	**$ 2,272**	**$ -**	**$ 25,025**	**$ 123**	**$ (17,285)**	**$ 2,675,606**
Liabilities and Partners' Capital							
Accounts payable & accrued liabilites - related party	$ 45,261	$ 10	$ -	$ -	$ 193	$ (190)	$ 45,274
Accrued interest payable	14,072	-	-	-	-	-	14,072
Current portion of long-term debt	-	-	-	1,042	-	-	1,042
Other current liabilities	1,485	-	-	-	-	-	1,485
Long-term debt	1,169,063	-	-	8,091	-	-	1,177,154
Asset retirement obligations	22,294	1,027	-	-	-	-	23,321
Total liabilities	**$ 1,252,175**	**$ 1,037**	**$ -**	**$ 9,133**	**$ 193**	**$ (190)**	**$ 1,262,348**
CrownRock, L.P. Partners' Capital	1,413,296	1,235	-	15,892	(70)	(17,057)	1,413,296
Non-controlling interest in subsidiary	-	-	-	-	-	(38)	(38)
Total Liabilities and Partners' Capital	**$ 2,665,471**	**$ 2,272**	**$ -**	**$ 25,025**	**$ 123**	**$ (17,285)**	**$ 2,675,606**

O. Supplemental Guarantor Information (Continued)

	For the Three Months Ended June 30, 2019						
	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	$ 210,555	$ 146	$ -	$ 578	$ 17	$ (578)	$ 210,718
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	46,544	281	-	-	3	-	46,828
Exploration costs	406	-	-	-	-	-	406
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	87,372	30	-	204	-	-	87,606
General and administrative	6,659	-	-	-	20	(578)	6,101
Operating income (loss)	69,574	(165)	-	374	(6)	-	69,777
Gain on derivatives not designated as hedges	38,170	-	-	-	-	-	38,170
Interest expense	(19,047)	-	-	(115)	-	-	(19,162)
Other income (expense)	1,464	-	-	-	-	(90)	1,374
Net income (loss)	90,161	(165)	-	259	(6)	(90)	90,159
Net loss attributable to non-controlling interest	-	-	-	-	-	2	2
Net income (loss) attributable to CrownRock, L.P.	$ 90,161	$ (165)	$ -	$ 259	$ (6)	$ (88)	$ 90,161
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ 90,161	$ (165)	$ -	$ 259	$ (6)	$ (90)	$ 90,159
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	2	2
Comprehensive income (loss) attributable to CrownRock, L.P.	$ 90,161	$ (165)	$ -	$ 259	$ (6)	$ (88)	$ 90,161

	For the Three Months Ended June 30, 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	$ 148,989	$ 275	$ -	$ 590	$ 11	$ (590)	$ 149,275
Gain on sales and exchanges of oil and natural gas properties	63,253	-	-	-	-	-	63,253
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	29,810	306	-	-	2	-	30,118
Exploration costs	2,254	-	-	-	-	-	2,254
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	49,057	29	-	201	47	-	49,334
General and administrative	6,835	-	-	-	19	(590)	6,264
Operating income (loss)	124,286	(60)	-	389	(57)	-	124,558
Loss on derivatives not designated as hedges	(14,747)	-	-	-	-	-	(14,747)
Interest expense	(16,894)	-	-	(127)	-	-	(17,021)
Other income (expense)	498	-	-	-	-	(173)	325
Net income (loss)	93,143	(60)	-	262	(57)	(173)	93,115
Net loss attributable to non-controlling interest	-	-	-	-	-	28	28
Net income (loss) attributable to CrownRock, L.P.	$ 93,143	$ (60)	$ -	$ 262	$ (57)	$ (145)	$ 93,143
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ 93,143	$ (60)	$ -	$ 262	$ (57)	$ (173)	$ 93,115
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	28	28
Comprehensive income (loss) attributable to CrownRock, L.P.	$ 93,143	$ (60)	$ -	$ 262	$ (57)	$ (145)	$ 93,143

O. Supplemental Guarantor Information (Continued)

	For the Six Months Ended June 30, 2019						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
				(In thousands)			
Condensed Statement of Operations							
Revenues and losses:							
Oil and natural gas sales, rental income, transportation, SWD income, surface ownership and fresh water supply income	$ 401,500	$ 475	$ -	$ 1,155	$ 27	$ (1,155)	$ 402,002
Loss on sales and exchanges of oil and natural gas properties	(84)	-	-	-	-	-	(84)
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	88,101	638	-	-	6	-	88,745
Exploration costs	1,241	-	-	-	-	-	1,241
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	157,221	61	-	404	-	-	157,686
General and administrative	13,448	-	-	-	38	(1,155)	12,331
Operating income (loss)	141,405	(224)	-	751	(17)	-	141,915
Loss on derivatives not designated as hedges	(157,843)	-	-	-	-	-	(157,843)
Interest expense	(37,222)	-	-	(230)	-	-	(37,452)
Other income (expense)	2,340	-	-	-	-	(288)	2,052
Net income (loss)	(51,320)	(224)	-	521	(17)	(288)	(51,328)
Net loss attributable to non-controlling interest	-	-	-	-	-	8	8
Net income (loss) attributable to CrownRock, L.P.	$ (51,320)	$ (224)	$ -	$ 521	$ (17)	$ (280)	$ (51,320)
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ (51,320)	$ (224)	$ -	$ 521	$ (17)	$ (288)	$ (51,328)
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	8	8
Comprehensive income (loss) attributable to CrownRock, L.P.	$ (51,320)	$ (224)	$ -	$ 521	$ (17)	$ (280)	$ (51,320)

	For the Six Months Ended June 30, 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	$ 290,926	$ 630	$ -	$ 1,158	$ 20	$ (1,158)	$ 291,576
Gain on sales and exchanges of oil and natural gas properties	63,253	-	-	-	-	-	63,253
Costs and expenses:							
Lease operating expenses and production and ad valorem taxes	58,160	648	-	-	5	-	58,813
Exploration costs	2,259	-	-	-	-	-	2,259
Depreciation, depletion and amortization, impairment of oil and natural gas properties and accretion of discount on ARO	93,991	57	-	395	95	-	94,538
General and administrative	13,125	-	-	1	37	(1,158)	12,005
Operating income (loss)	186,644	(75)	-	762	(117)	-	187,214
Loss on derivatives not designated as hedges	(6,197)	-	-	-	-	-	(6,197)
Interest expense	(32,251)	-	-	(254)	-	-	(32,505)
Other income (expense)	793	-	-	40	-	(414)	419
Net income (loss)	148,989	(75)	-	548	(117)	(414)	148,931
Net loss attributable to non-controlling interest	-	-	-	-	-	58	58
Net income (loss) attributable to CrownRock, L.P.	$ 148,989	$ (75)	$ -	$ 548	$ (117)	$ (356)	$ 148,989
Statement of Comprehensive Income (Loss)							
Net income (loss)	$ 148,989	$ (75)	$ -	$ 548	$ (117)	$ (414)	$ 148,931
Less: Comprehensive loss attributable to the non-controlling interest	-	-	-	-	-	58	58
Comprehensive income (loss) attributable to CrownRock, L.P.	$ 148,989	$ (75)	$ -	$ 548	$ (117)	$ (356)	$ 148,989

O. Supplemental Guarantor Information (Continued)

Condensed Statement of Cash Flows	For the Six Months Ended June 30, 2019 (In thousands)						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
Cash flows from operating activities	$ 282,635	$ (143)	$ -	$ 936	$ 2	$ -	$ 283,430
Cash flows from investing activities:							
Acquisition of leasehold and oil and natural gas properties	(7,158)	-	-	-	-	-	(7,158)
Capital expenditures on oil and natural gas properties	(372,631)	(2)	-	-	-	-	(372,633)
Additions to other property and equipment	(8,072)	-	-	(34)	-	-	(8,106)
Investment in subsidiary	300	-	-	-	-	(300)	-
Total cash flows from investing activities	$ (387,561)	$ (2)	$ -	$ (34)	$ -	$ (300)	$ (387,897)
Cash flows from financing activities:							
Distributions to parent	-	-	-	(300)	-	300	-
Distributions to partners	(16,028)	-	-	-	-	-	(16,028)
Repayments of long-term borrowings under construction loan	-	-	-	(515)	-	-	(515)
Proceeds from long-term borrowings under credit facility	170,000	-	-	-	-	-	170,000
Repayments of long-term borrowings under credit facility	(55,000)	-	-	-	-	-	(55,000)
Payments for loan and debt issue costs	(4,241)	-	-	-	-	-	(4,241)
Total cash flows from financing activities	$ 94,731	$ -	$ -	$ (815)	$ -	$ 300	$ 94,216
Net decrease in cash, cash equivalents and restricted cash	$ (10,195)	$ (145)	$ -	$ 87	$ 2	$ -	$ (10,251)
Cash, cash equivalents and restricted cash, beginning of period	73,680	166	-	214	93	-	74,153
Cash,cash equivalents and restricted cash, end of period	$ 63,485	$ 21	$ -	$ 301	$ 95	$ -	$ 63,902

Condensed Statement of Cash Flows	For the Six Months Ended June 30, 2018 (In thousands)						
	CrownRock, LP	Roddy, LLC	CrownRock Finance, Inc.	Canvasback Properties, LLC	Abajo, LLC	Eliminations	Consolidated
Cash flows from operating activities	$ 187,849	$ (2)	$ -	$ 955	$ (7)	$ -	$ 188,795
Cash flows from investing activities:							
Acquisition of leasehold and oil and natural gas properties	(4,564)	-	-	-	-	-	(4,564)
Capital expenditures on oil and natural gas properties	(289,793)	-	-	-	-	-	(289,793)
Additions to other property and equipment	(1,489)	-	-	(636)	-	-	(2,125)
Contributions to equity method investments	(1,782)	-	-	-	-	-	(1,782)
Investment in subsidiary	(350)	-	-	-	-	350	-
Total cash flows from investing activities	$ (297,978)	$ -	$ -	$ (636)	$ -	$ 350	$ (298,264)
Cash flows from financing activities:							
Capital contribution from parent	-	-	-	350	-	(350)	-
Distributions to partners	(5,171)	-	-	-	-	-	(5,171)
Proceeds from issuance of 5.625% Senior Notes due 2025	181,781	-	-	-	-	-	181,781
Repayments of long-term borrowings under construction loan	-	-	-	(491)	-	-	(491)
Proceeds from long-term borrowings under credit facility	55,000	-	-	-	-	-	55,000
Repayments of long-term borrowings under credit facility	(55,000)	-	-	-	-	-	(55,000)
Payments for loan and debt issue costs	(2,644)	-	-	-	-	-	(2,644)
Purchase of treasury units	(17)	-	-	-	-	-	(17)
Total cash flows from financing activities	$ 173,949	$ -	$ -	$ (141)	$ -	$ (350)	$ 173,458
Net increase (decrease) in cash and cash equivalents	$ 63,820	$ (2)	$ -	$ 178	$ (7)	$ -	$ 63,989
Cash and cash equivalents, beginning of period	94,874	967	-	90	136	-	96,067
Cash and cash equivalents, end of period	$ 158,694	$ 965	$ -	$ 268	$ 129	$ -	$ 160,056

* *

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

The following discussion and analysis should be read in conjunction with "Selected Financial Data" and the accompanying consolidated financial statements and related notes included elsewhere in this report. 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, extensive infrastructure, wells with long reserve lives and multiple producing 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 EIA, 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 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 and the beginning of 2017 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. In 2017, we drilled spacing tests, with wells drilled on interwell spacing ranging from 306 feet to 783 feet (average of 472 feet) and vertical bench separation as tight as 130 feet. During 2017, we increased horizontal drilling and drilled approximately 60% more horizontal wells as compared to 2016. Also during 2017, 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. During 2018, we continued our acceleration of our horizontal drilling, mainly drilling multi-well pads with interwell spacing ranging from 312 feet to 690 feet (average of 493 feet). We drilled approximately 27% more horizontal wells as compared to 2017. We believe our horizontal well inventory will be developed most efficiently through full section development, which is the practice of drilling multiple wellbores in a section and completing the wellbores after the multiple wellbores have been drilled.

We have a large inventory of horizontal drilling opportunities. This inventory is evolving as a result of several factors, including additional geological information obtained and acreage changes resulting from property exchanges. As of June 30, 2019, on our Midland Basin acreage, we have identified 3,304 net Tier 1 and 1,366 net Tier 2 horizontal locations that can be drilled wholly or partially on our acreage based primarily on current industry practice of 660-foot interwell spacing with some 880-foot or 1,320-foot spacing in certain areas and benches. Since initiating our horizontal program in January 2015, through March 31, 2019, we have drilled a total of 204 net horizontal locations. We count inventory well locations within benches in the Midland Basin that we believe will be prospective based on success of offset operators, or vertical well experience in drilling through and producing from these benches, and our analysis of available engineering and geological data both within and by the boundaries of our leases. Of the 3,304 net Tier 1 horizontal locations, 2,961 are fully controlled on our acreage in 1.5-mile or 2-mile laterals, and 343 can be drilled when pooled with offset operators to create 1.5-mile laterals on co-owned acreage. Of the 2,961 fully controlled Tier 1 locations, 427 are included as PUD locations in our latest reserve report dated July 1, 2019. We define a Tier 1 location as having an existing economic horizontal well or wells on or proximal to our acreage. Tier 2 locations have similar geologic parameters as Tier 1 locations, but lack existing offset production required to be considered at Tier 1.

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 six months ended June 30, 2019, as compared to the six months ended June 30, 2018 included the following highlights:

- The Partnership incurred a net loss of $51.3 million for the first six months of 2019, as compared to net income of $149.0 million for the first six months in 2018. The decrease in earnings is primarily due to:

  - a $29.9 million increase in oil and natural gas production costs in 2019 due to increases in lease operating expenses and production and ad valorem taxes;

  - a $63.2 million increase in depreciation, depletion and amortization due to increased capitalized costs and increased oil and natural gas production associated with the new wells that were successfully drilled and completed in 2018 and 2019;

  - a $157.8 million loss on derivatives during the first six months in 2019, comprised of $24.8 million gain on cash settlements offset by a $182.6 million mark-to-market loss primarily the result of increases in forward looking crude oil prices, as compared to a $6.2 million loss in the first six months in 2018, comprised of $15.4 million gain on cash settlements offset by a $21.6 million mark-to-market loss;

  - a $5.0 million increase in interest expense during 2019 due to an increase in the outstanding debt balance as compared to 2018;

  - an $84 thousand non-cash loss on exchange of oil and natural properties during the first six months of 2019, compared to $63.3 million of non-cash gains on exchanges of oil and natural gas properties during the first six months of 2018;

  - offset by:

    - a $103.4 million increase in oil and natural gas revenues as a result of a 67% increase in production (oil equivalent) offset by a 18% decrease in average realized commodity prices (oil equivalent, excluding derivatives); and

    - a $7.0 million increase in other revenue during the first six months of 2019 as compared to the first six months in 2018.

- Average daily sales volumes increased during the first six months of 2019 by 67% from 34,434 Boe per day during the first six months in 2018 to 57,406 Boe per day during the first six months in 2019.

- Net cash provided by operating activities increased by $94.6 million to $283.4 million for the first six months in 2019, as compared to $188.8 million for the first six months in 2018, principally due to increases in oil and natural gas revenues, increases in cash settlements on crude oil derivatives, changes in working capital items and increases in other revenues offset by increases in production costs.

- At June 30, 2019, we had $115.0 million outstanding and our availability under our credit facility was $485.0 million.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to (i) relatively minor changes in the supply of and demand for oil, natural gas and natural gas liquids, (ii) market uncertainty and (iii) a variety of additional factors that are beyond our control. Factors that may impact future commodity prices, including the price of oil, natural gas and natural gas liquids, include, but are not limited to:

- 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 may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note H of the Notes to the Condensed Consolidated Financial Statements for additional information regarding our commodity derivative positions as of June 30, 2019.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. The average oil price and the average natural gas price was moderately lower during the comparable periods of 2019 measured against 2018. The following table sets forth the average NYMEX oil and natural gas prices for the three and six months ended June 30, 2019 and 2018, as well as the high and low NYMEX price for the same periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Average NYMEX prices:				
Oil (Bbl)	$ 59.96	$ 67.91	$ 57.37	$ 65.48
Natural gas (MMBtu)	$ 2.51	$ 2.83	$ 2.69	$ 2.84
High and Low NYMEX prices:				
Oil (Bbl):				
High	$ 66.30	$ 74.15	$ 66.30	$ 74.15
Low	$ 51.14	$ 62.06	$ 45.41	$ 59.19
Natural gas (MMBtu):				
High	$ 2.71	$ 3.02	$ 3.59	$ 3.63
Low	$ 2.19	$ 2.66	$ 2.19	$ 2.55

Although we have hedged a portion of our estimated oil production through 2020, we may still be adversely affected by continuing and prolonged declines in the price of oil and natural gas. We have planned our 2019 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.

Recent Events

Decline in natural gas market prices and revenues. During the six months ended June 30, 2019, the market prices that we received for our natural gas sales have decreased significantly and have resulted in decreased natural gas revenues. The average natural gas market price indices in the Permian Basin which are referenced in all our natural gas sales contracts, Inside FERC – El Paso and Inside FERC – Waha, were $0.14 per MMBtu and ($0.07) per MMBtu, respectively, for the three months ended June 30, 2019, prior to deductions for fees and transportation. As a result, our average realized price for natural gas for the three months ended June 30, 2019 was ($0.11) per Mcf. Although our natural gas production has continued to increase, this negative pricing situation resulted in the Partnership reporting negative natural gas sales of approximately ($0.6 million) for the three months ended June 30, 2019.

This decline in market prices of natural gas in the Permian Basin is due to the production of natural gas in the Midland and Delaware Basins reaching a point that it temporarily surpasses the demand in the markets to which such gas is sold. We do not know how long this situation may persist. Further, we have not hedged any portion of our natural gas production and therefore will continue to be adversely affected by continuing and prolonged declines in natural gas prices. Additionally, our natural gas and NGL sales volumes and revenue during the six months ended June 30, 2019 have been negatively affected by gas processing plant fires and the resulting force majeure provisions invoked by such processors. Natural gas revenues have historically been the smallest component of our aggregate revenue stream, as compared to crude oil and NGL revenues. For the six months ended June 30, 2019 and the year ended December 31, 2018, natural gas sales represented 1.0% and 2.5%, respectively, of our total oil, natural gas and NGL sales. As a result, we believe the impact of this price decline and the force majeure events on the Partnership's 2019 cash flows will be minimal and we do not anticipate reducing our planned 2019 capital expenditures.

Midland WTI – Cushing WTI basis differential volatility. The decrease in our realized oil price, excluding derivatives, compared to the average NYMEX market price that we experienced during the year ended December 31, 2018, which was primarily due to the increase in the Midland – Cushing differential deduction, has improved during the six months ended June 30, 2019, but continues to be volatile. The Midland – Cushing differential deduction is a component of the pricing formula in all our crude oil sales contracts. This basis differential (referred to as the "Mid-Cush differential") between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil has increased due to the production of oil in the Midland Basin reaching a point that it temporarily surpasses the available transportation and refining capacity in the area. Although we have hedged the Mid-Cush differential for a portion of our estimated oil production through December 2020, our results of operations and financial condition could be negatively affected if commodity basis differentials versus NYMEX increase as they did during a portion of 2018. The following table sets forth the (1) average NYMEX oil prices, (2) realized oil prices, the differential between (1) and (2) and the effect of the cash receipts from crude oil basis derivatives for the three and six months ended June 30, 2019 and 2018:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2019	2018	2019	2018
Realized oil price, excluding derivatives	$ 52.66	$ 60.35	$ 54.00	$ 61.92
Avg. NYMEX futures price	$ 59.96	$ 67.91	$ 57.37	$ 65.48
Basis differential, incl. transportation	$ (7.30)	$ (7.56)	$ (3.37)	$ (3.56)
Basis derivative effect (cash settlements received)	$ 1.22	$ 3.13	$ 0.90	$ 1.74
Net basis differential, including derivatives	$ (6.08)	$ (4.43)	$ (2.47)	$ (1.82)

2019 capital expenditure plan. Our capital expenditure plan for drilling and completion activities for 2019 will range from approximately $700 million to $850 million, all of which has been allocated to drilling activities in the Permian Basin. We currently believe that our operating cash flows alone will not meet both our short-term working capital requirements and current 2019 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 reduce our capital spending program to be within our cash flow.

Our capital expenditure plan does not include acquisitions, outside operated projects or asset retirement obligations. The following is a summary of our 2019 capital expenditure plan for drilling and completion activities:

	2019 Capital Expenditure Plan						
	Capital ($ millions)	Gross Wells		Net Wells		CrownQuest Operated Rigs (Average)	
		Horizontal	Vertical	Horizontal	Vertical	Horizontal	Vertical
Permian Basin drilling activities	$700 - $850	107	22	97	21	6.75	1

In addition to our drilling and completion capital expenditures, our 2019 capital expenditure plan includes approximately $53 million for infrastructure (such as tank batteries, gathering pipelines, water sources, salt water disposal, and frac pits) in order to support our drilling activity and the resulting increase in production.

Derivative Financial Instruments

Derivative financial instrument exposure. As of June 30, 2019, the fair value of our financial derivatives was a net asset of $68.1 million. All but one 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. The one counterparty to our financial derivatives that is not a party to our credit agreement is a major market participant of high credit quality. Under the terms of our financial derivatives instruments with this counterparty, we do not have exposure to margin calls and our relationship is on an unsecured basis subject to a credit limit established by the counterparty. 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 June 30, 2019 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	949	126	1,075	739.7	96.5	836.2
San Juan Basin	-	49	49	-	30.1	30.1
Paradox Basin	1	3	4	0.8	1.6	2.4
Total	950	178	1,128	740.5	128.2	868.7

The following table sets forth the number of productive oil and natural gas wells attributable to our properties as of December 31, 2018.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian Basin	855	126	981	693.4	82.5	775.9
San Juan Basin	7	53	60	7.0	33.6	40.6
Paradox Basin	-	2	2	-	1.2	1.2
Total	862	181	1,043	700.4	117.3	817.7

Results of Operations

The following table sets forth production and operating data for the three and six months ended June 30, 2019 and 2018.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2019	2018	2019	2018
Production and operating data:				
Net production volumes:				
Oil (Bbl)	3,565,398	2,099,354	6,585,040	3,982,247
Natural gas (Mcf)	5,251,471	2,906,250	9,555,132	5,464,700
Natural gas liquids (Bbl)	1,267,152	705,206	2,212,848	1,339,499
Oil equivalent (Boe)	5,707,795	3,288,935	10,390,410	6,232,529
Average daily production volumes:				
Oil (Bbl)	39,180	23,070	36,381	22,001
Natural gas (Mcf)	57,708	31,937	52,791	30,192
Natural gas liquids (Bbl)	13,925	7,750	12,226	7,401
Oil equivalent (Boe)	62,723	36,142	57,406	34,434
Average prices:				
Oil, without derivatives ($/Bbl)	$ 52.66	$ 60.35	$ 54.00	$ 61.92
Oil, with derivatives ($/Bbl) (a)	$ 55.48	$ 63.43	$ 57.77	$ 65.80
Natural gas, without derivatives ($/Mcf)	$ (0.11)	$ 1.13	$ 0.37	$ 1.44
Natural gas liquids, without derivatives ($/Bbl)	$ 11.18	$ 17.68 (c)	$ 10.92 (b)	$ 18.97
Oil equivalent, without derivatives ($/Boe)	$ 35.28	$ 43.31	$ 36.89	$ 44.90
Oil equivalent, with derivatives ($/Boe) (a)	$ 37.04	$ 45.28	$ 39.27	$ 47.38
Operating costs and expenses per Boe:				
Lease operating expenses and workover costs	$ 5.94	$ 6.79	$ 6.32	$ 6.89
Oil and natural gas production and ad valorem taxes	$ 2.26	$ 2.37	$ 2.22	$ 2.54
Depreciation, depletion and amortization	$ 15.20	$ 14.70	$ 15.00	$ 14.87
General and administrative	$ 1.07	$ 1.90	$ 1.19	$ 1.93

(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.

(b) The first quarter of 2019 includes a reduction of approximately $3.3 million in NGL sales related to a change in our revenue accrual estimate. This change was driven by a substantial change in the relationship between NGL and natural gas prices utilized in our NGL accrual calculations in the fourth quarter of 2018. Excluding this adjustment, we estimate the average price of natural gas liquids, without derivatives, would be $12.40 per Bbl for the six months ended June 30, 2019.

(c) The second quarter of 2018 includes a reduction of approximately $1.8 million in NGL sales related to a change in our revenue accrual estimate. This change was driven by changes in NGL index prices and realizations utilized in our NGL accrual calculations in the first quarter of 2018. Excluding this adjustment, we estimate the average price of natural gas liquids, without derivatives, would be $20.23 per Bbl.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	2019	2018	2019	2018
Cash receipts from derivatives not designated as hedges:				
Oil and oil basis derivatives	$ 10,062	$ 6,474	$ 24,814	$ 15,440

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 June 30, 2019 Compared to Three Months Ended June 30, 2018

Oil and natural gas revenues.

	Three Months Ended June 30,	
	2019	2018
	(In thousands)	
Oil sales	$ 187,756	$ 126,695
Natural gas sales	(579)	3,271
Natural gas liquids sales	14,167	12,469
Total oil and natural gas sales	$ 201,344	$ 142,435

Revenue from oil and natural gas operations was $201.3 million for the three months ended June 30, 2019, an increase of $58.9 million (41%) from $142.4 million for the three months ended June 30, 2018. This increase was primarily due to a 74% increase in production (oil equivalent) as a result of increased drilling and completion activity during the three months ended June 30, 2019 as compared to the three months ended June 30, 2018, offset by a 19% decrease in oil, natural gas and natural gas liquids prices (oil equivalent excluding the effects of derivative activities) during 2019 as compared to 2018. Specifics include the following:

- the average realized oil price (excluding the effects of derivative activities) was $52.66 per Bbl during the three months ended June 30, 2019, a decrease of 13% from $60.35 per Bbl during the three months ended June 30, 2018;
- total oil production was 3,565,398 Bbl for the three months ended June 30, 2019, an increase of 1,466,044 Bbl (70%) from 2,099,354 Bbl for the three months ended June 30, 2018;
- the average realized natural gas price (excluding the effects of derivative activities) was $(0.11) per Mcf during the three months ended June 30, 2019, a decrease of 110% from $1.13 per Mcf during the three months ended June 30, 2018;
- total natural gas production was 5,251,471 Mcf for the three months ended June 30, 2019, an increase of 2,345,221 Mcf (81%) from 2,906,250 Mcf for the three months ended June 30, 2018;
- the average realized natural gas liquids price (excluding the effects of derivative activities) was $11.18 per Bbl during the three months ended June 30, 2019, a decrease of 37% from $17.68 per Bbl during the three months ended June 30, 2018; and
- total natural gas liquids production was 1,267,152 Bbl for the three months ended June 30, 2019, an increase of 561,946 Bbl (80%) from 705,206 Bbl for the three months ended June 30, 2018.

Production expenses. The following table provides the components of our total oil and natural gas production expenses for the three months ended June 30, 2019 and 2018:

	Three Months Ended June 30,			
	2019		2018	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
Lease operating expenses	$ 33,910	$ 5.94	$ 22,340	$ 6.79
Production and ad valorem taxes	12,918	2.26	7,778	2.37
Total oil and natural gas production expenses	$ 46,828	$ 8.20	$ 30,118	$ 9.16

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 $33.9 million ($5.94 per Boe) for the three months ended June 30, 2019 which was an increase of $11.6 million (52%) from $22.3 million ($6.79 per Boe) for the three months ended June 30, 2018. 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 2019 and 2018, and an increase in well servicing costs on downhole and surface equipment. On a per Boe basis, these servicing costs decreased 19% which approximated $4.5 million ($0.79 per Boe) for the three months ended June 30, 2019 as compared to approximately $3.2 million ($0.97 per Boe) for the three months ended June 30, 2018.

The 13% decrease in lease operating expenses per Boe was primarily due to the 74% increase in production (oil equivalent), offset by the factors listed above. The increase in production was a result of successful drilling efforts during 2019 and 2018 from our active Midland Basin horizontal drilling program. This resulted in higher per well production rates in 2019 as compared to 2018.

Production and ad valorem taxes. The Partnership recorded production and ad valorem taxes of $12.9 million for the three months ended June 30,2019, as compared to $7.8 million for the three months ended June 30, 2018. 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 June 30, 2019 and 2018.

	Three Months Ended June 30,			
	2019		2018	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Production taxes	$ 9,498	$ 1.66	$ 6,931	$ 2.11
Ad Valorem taxes	3,420	0.60	847	0.26
Total production and ad valorem taxes	$ 12,918	$ 2.26	$ 7,778	$ 2.37

Production taxes per unit of production were $1.66 per Boe for the three months ended June 30, 2019, a decrease of 21% from $2.11 per Boe for the three months ended June 30, 2018. The oil revenue/gas revenue components of total revenue from oil and natural gas operations in 2019 were 93%/7% as compared to 2018 at 89%/11%. Production taxes, as a percentage of oil and natural gas revenues, were consistent at approximately 5% for the three months ended June 30, 2019 and 2018. Over the same period, our per Boe commodity prices (excluding the effects of derivatives) decreased 19%.

Exploration costs. Exploration costs were $0.4 million for the three months ended June 30, 2019. This 2019 amount was primarily comprised of dry hole expense on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas. Exploration costs were $2.3 million for the three months ended June 30, 2018. This 2018 amount was primarily comprised of dry hole expense of two oil and natural gas wells on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the three months ended June 30, 2019 and 2018:

	Three Months Ended June 30,			
	2019		2018	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 85,610	$ 15.00	$ 47,630	$ 14.48
Depletion and depreciation of other property and equipment	1,126	0.20	721	0.22
Total depletion, depreciation and amortization	$ 86,736	$ 15.20	$ 48,351	$ 14.70
Average oil price used to estimate proved oil reserves at period end	$ 57.90		$ 54.15	
Average natural gas price used to estimate proved natural gas reserves at period end	$ 3.02		$ 2.92	

Depletion of proved oil and natural gas properties was $85.6 million ($15.00 per Boe) for the three months ended June 30, 2019, an increase of $38.0 million (80%) from $47.6 million ($14.48 per Boe) for the three months ended June 30, 2018. 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 2018 and 2019 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 2018 and 2019.

The 4% increase in depletion expense per Boe was primarily due to the increase in production from period to period offset by increases in proved developed producing reserves and total proved reserves of 19% and 29%, respectively, at June 30, 2019 as compared to June 30, 2018.

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended June 30, 2019 and 2018:

	Three Months Ended June 30,			
	2019		2018	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 5,141	$ 0.90	$ 5,149	$ 1.56
Non-cash unit-based compensation	961	0.17	1,115	0.34
Total general and administrative expenses	$ 6,102	$ 1.07	$ 6,264	$ 1.90

General and administrative expenses were approximately $6.1 million ($1.07 per Boe) for the three months ended June 30, 2019, a decrease of $0.2 million (3%) from $6.3 million ($1.90 per Boe) for the three months ended June 30, 2018. The decrease in general and administrative expenses is primarily due to the decrease in non-cash unit-based compensation expense. The 44% decrease in general and administrative expenses per Boe was primarily due to the increase in production from period to period and the factor listed above.

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 June 30, 2019 and 2018:

(in thousands)	**Three Months Ended June 30, 2019**	**2018**
Cash receipts:		
Commodity derivatives - NYMEX-WTI oil	$ 5,713	$ 6,474
Commodity derivatives - Midland-Cushing oil	4,349	-
Mark-to-market gain (loss):		
Commodity derivatives - NYMEX-WTI oil	35,043	(21,221)
Commodity derivatives - Midland-Cushing oil	(6,935)	-
Realized and unrealized net gain (loss) on derivatives	$ 38,170	$ (14,747)

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the three months ended June 30, 2019 and 2018:

($ in thousands)	**Three Months Ended June 30, 2019**	**2018**
Interest expense	$ 19,162	$ 17,021
Weighted average interest rate	5.90%	6.06%
Weighted average cash interest rate	5.64%	5.79%
Weighted average debt balance	$ 1,299,096	$ 1,124,175

The increase in weighted average debt balance during the three months ended June 30, 2019 was due to the issuance of 2025 Senior Notes in May 2018 and the advances on the Credit Facility in 2019. The increase in interest expense is due to an increase in the weighted average debt balance between periods. The decrease in the weighted average interest rate and the weighted average cash interest rate during the three months June 30, 2019 is due to larger advances and the lower weighted average interest rate on the advances on the Credit Facility during the three months ended June 30, 2019 compared to the amount of the advances and the average interest rate on the advances on the Credit Facility during the three months ended June 30, 2018.

Six Months Ended June 30, 2019 Compared to Six Months Ended June 30, 2018

Oil and natural gas revenues.

	Six Months Ended June 30, 2019	**2018**
	(In thousands)	
Oil sales	$ 355,571	$ 246,594
Natural gas sales	3,531	7,851
Natural gas liquids sales	24,155	25,414
Total oil and natural gas sales	$ 383,257	$ 279,859

Revenue from oil and natural gas operations was $383.3 million for the six months ended June 30, 2019, an increase of $103.4 million (37%) from $279.9 million for the six months ended June 30, 2018. This increase was primarily due to a 67% increase in production (oil equivalent) as a result of increased drilling and completion activity during the six months ended June 30, 2019 as compared to the six months ended June 30, 2018, offset by a 18% decrease in oil, natural gas and natural gas liquids prices (oil equivalent excluding the effects of derivative activities) during 2019 as compared to 2018. Specifics include the following:

- the average realized oil price (excluding the effects of derivative activities) was $54.00 per Bbl during the six months ended June 30, 2019, a decrease of 13% from $61.92 per Bbl during the six months ended June 30, 2018;
- total oil production was 6,585,040 Bbl for the six months ended June 30, 2019, an increase of 2,602,793 Bbl (65%) from 3,982,247 Bbl for the six months ended June 30, 2018;
- the average realized natural gas price (excluding the effects of derivative activities) was $0.37 per Mcf during the six months ended June 30, 2019, a decrease of 74% from $1.44 per Mcf during the six months ended June 30, 2018;
- total natural gas production was 9,555,132 Mcf for the six months ended June 30, 2019, an increase of 4,090,432 Mcf (75%) from 5,464,700 Mcf for the six months ended June 30, 2018;
- the average realized natural gas liquids price (excluding the effects of derivative activities) was $10.92 per Bbl during the six months ended June 30, 2019, a decrease of 42% from $18.97 per Bbl during the six months ended June 30, 2018; and
- total natural gas liquids production was 2,212,848 Bbl for the six months ended June 30, 2019, an increase of 873,349 Bbl (65%) from 1,339,499 Bbl for the six months ended June 30, 2018.

Production expenses. The following table provides the components of our total oil and natural gas production expenses for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,			
	2019		2018	
(in thousands, except per Boe data)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 65,648	$ 6.32	$ 42,963	$ 6.89
Production and ad valorem taxes	23,097	2.22	15,850	2.54
Total oil and natural gas production expenses	$ 88,745	$ 8.54	$ 58,813	$ 9.43

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 $65.6 million ($6.32 per Boe) for the six months ended June 30, 2019 which was an increase of $22.6 million (53%) from $43.0 million ($6.89 per Boe) for the six months ended June 30, 2018. 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 2019 and 2018, and an increase in well servicing costs on downhole and surface equipment. On a per Boe basis, these servicing costs decreased 36% which approximated $8.1 million ($0.78 per Boe) for the six months ended June 30, 2019 as compared to approximately $7.6 million ($1.22 per Boe) for the six months ended June 30, 2018.

The 8% decrease in lease operating expenses per Boe was primarily due to the 67% increase in production (oil equivalent), offset by the factors listed above. The increase in production was a result of successful drilling efforts during 2019 and 2018 from our active Midland Basin horizontal drilling program. This resulted in higher per well production rates in 2019 as compared to 2018.

Production and ad valorem taxes. The Partnership recorded production and ad valorem taxes of $23.1 million for the six months ended June 30, 2019, as compared to $15.9 million for the six months ended June 30, 2018. 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 six months ended June 30, 2019 and 2018.

	Six Months Ended June 30,			
	2019		2018	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
Production taxes	$ 18,146	$ 1.75	$ 13,557	$ 2.17
Ad Valorem taxes	4,951	0.47	2,293	0.37
Total production and ad valorem taxes	$ 23,097	$ 2.22	$ 15,850	$ 2.54

Production taxes per unit of production were $1.75 per Boe for the six months ended June 30, 2019, a decrease of 19% from $2.17 per Boe for the six months ended June 30, 2018. The oil revenue/gas revenue components of total revenue from oil and natural gas operations in 2019 were 93%/7% as compared to 2018 at 88%/12%. Production taxes, as a percentage of oil and natural gas revenues, were consistent at approximately 5% for the six months ended June 30, 2019 and 2018. Over the same period, our per Boe commodity prices (excluding the effects of derivatives) decreased 18%.

Exploration costs. Exploration costs were $1.2 million for the six months ended June 30, 2019. This 2019 amount was primarily comprised of dry hole expense on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas. Exploration costs were $2.3 million for the six months ended June 30, 2018. This 2018 amount was primarily comprised of dry hole expense of two oil and natural gas wells on the Spade Ranch property located in the Eastern Shelf of the Permian Basin of Texas.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,			
	2019		2018	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
Depletion of proved oil and natural gas properties	$ 153,398	$ 14.76	$ 91,247	$ 14.64
Depletion and depreciation of other property and equipment	2,454	0.24	1,432	0.23
Total depletion, depreciation and amortization	$ 155,852	$ 15.00	$ 92,679	$ 14.87
Average oil price used to estimate proved oil reserves at period end	$ 57.90		$ 54.15	
Average natural gas price used to estimate proved natural gas reserves at period end	$ 3.02		$ 2.92	

Depletion of proved oil and natural gas properties was $153.4 million ($14.76 per Boe) for the six months ended June 30, 2019, an increase of $62.2 million (68%) from $91.2 million ($14.64 per Boe) for the six months ended June 30, 2018. 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 2018 and 2019 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 2018 and 2019.

The 1% decrease in depletion expense per Boe was primarily due to the increase in proved developed producing reserves and total proved reserves of 19% and 21%, respectively, at June 30, 2019 as compared to June 30, 2018 offset by 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 six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,			
	2019		2018	
(in thousands, except per Boe data)	Amount	Per Boe	Amount	Per Boe
General and administrative expenses	$ 10,406	$ 1.00	$ 9,806	$ 1.58
Non-cash unit-based compensation	1,925	0.19	2,199	0.35
Total general and administrative expenses	$ 12,331	$ 1.19	$ 12,005	$ 1.93

General and administrative expenses were approximately $12.3 million ($1.19 per Boe) for the six months ended June 30, 2019, an increase of $0.3 million (3%) from $12.0 million ($1.93 per Boe) for the six months ended June 30, 2018. The increase in general and administrative expenses is due to increases in CrownQuest's staffing expenses resulting from the continued growth of the Partnership. The 38% decrease in general and administrative expenses per Boe was primarily due to the increase in production from period to period offset by the factors listed above.

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 six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,	
(in thousands)	2019	2018
Cash receipts:		
Commodity derivatives - NYMEX-WTI oil	$ 18,868	$ 15,440
Commodity derivatives - Midland-Cushing oil	5,946	-
Mark-to-market loss:		
Commodity derivatives - NYMEX-WTI oil	(140,457)	(21,637)
Commodity derivatives - Midland-Cushing oil	(42,200)	-
Realized and unrealized net loss on derivatives	$ (157,843)	$ (6,197)

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,	
($ in thousands)	2019	2018
Interest expense	$ 37,452	$ 32,505
Weighted average interest rate	5.99%	6.09%
Weighted average cash interest rate	5.71%	5.82%
Weighted average debt balance	$ 1,251,381	$ 1,067,471

The increase in weighted average debt balance during the six months ended June 30, 2019 was due to the issuance of 2025 Senior Notes in May 2018 and the advances on the Credit Facility in 2019. The increase in interest expense is due to an increase in the weighted average debt balance between periods. The decrease in the weighted average interest rate and the weighted average cash interest rate during the six months ended June 30, 2019 is due to larger advances and the lower weighted average interest rate on the advances on the Credit Facility during the six months ended June 30, 2019 compared to the amount of the advances and the average interest rate on the advances on the Credit Facility during the six months ended June 30, 2018.

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 six months ended June 30, 2019 and 2018 totaled $379.8 million and $294.4 million, respectively. Of these amounts, $7.2 million and $4.6 million, respectively, were used in the acquisition of proved oil and natural gas properties and undeveloped leasehold acreage in West Texas and $372.6 million and $289.8 million, respectively, were used in drilling and development. The 2019 expenditures were funded by cash flow from operations and borrowings under our credit facility. The 2018 expenditures were funded by cash flow from operations, borrowings under our credit facility and proceeds from the issuance of the 2025 Senior Notes in October 2017 and May 2018.

Our capital expenditure plan for drilling and completion activities for 2019 will range from approximately $700 million to $850 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 2019 capital expenditure plan includes approximately $53 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 2019 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 2019 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 $7.2 million and $4.6 million for the six months ended June 30, 2019 and 2018, respectively. The acquisitions during 2019 and 2018 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 six months ended June 30, 2019 and 2018.

Nonmonetary transactions. If it is deemed value-adding, we will enter into exchange agreements with third parties to exchange proved and unproved oil and natural gas properties as part of our strategy to consistently pursue financially viable deals to further block-up our acreage and thereby enhance our horizontal well drilling inventory in the Permian Basin.

During the six months ended June 30, 2019, we completed multiple nonmonetary transactions. These transactions included the exchange of both proved and unproved oil and natural gas properties. One of these transactions was accounted for at fair value and, as a result we recorded a loss of approximately $84 thousand.

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 and other obligations.

We had the following contractual obligations at June 30, 2019:

	Payments due by Period				
(in thousands)	**Total**	**2019**	**2020-2021**	**2022-2023**	**2024 and Thereafter**
Long-term debt (a)	$ 1,308,790	$ 527	$ 2,239	$ 2,467	$ 1,303,557
Cash interest expense on debt (b)	455,999	35,837	143,189	142,950	134,023
Asset retirement obligations (c)	24,759	197	2,421	525	21,616
Operating lease obligations (d)	9,739	1,155	3,282	2,484	2,818
Total	$ 1,799,287	$ 37,716	$ 151,131	$ 148,426	$ 1,462,014

(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 "2019" column is accrued interest at June 30, 2019, for our unsecured senior notes of approximately $14.3 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 June 30, 2019. 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 2019 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 increase (decrease) in cash and cash equivalents for the six months ended June 30, 2019 and 2018:

	Six Months Ended June 30,	
(in thousands)	**2019**	**2018**
Net cash provided by operating activities	$ 283,430	$ 188,795
Net cash used in investing activities	(387,897)	(298,264)
Net cash provided by financing activities	94,216	173,458
Net increase (decrease) in cash, cash equivalents and restricted cash	$ (10,251)	$ 63,989

Cash flow from operating activities. The increase in operating cash flows during the six months ended June 30, 2019 over 2018 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 six months ended June 30, 2019 and 2018, we invested $379.8 million and $294.4 million, respectively, for additions to, and acquisitions of, oil and natural gas properties. During the six months ended June 30, 2019 and 2018, we also invested $8.1 million and $2.1 million, respectively, in other property and equipment. Additionally, during 2018, we invested $1.8 million in the Silvertip investment.

Cash flow from financing activities. Net cash provided by financing activities of $94.2 million for the six months ended June 30, 2019 primarily consisted of borrowings under the credit facility. Offsetting such borrowings in 2019 were debt issuance costs for the credit facility, repayments of our credit facility, repayments of borrowings under the construction loan and distributions to our sole limited partner. Net cash provided by financing activities of $173.5 million for the six months ended June 30, 2018 primarily consisted of the issuance of additional 2025 Senior Notes. Offsetting such borrowings in 2018 were associated debt issuance costs, repayment of our credit facility, repayments of borrowings under the construction loan and distributions to our sole limited partner.

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 are 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. The amount of such tax distributions for 2019 is expected to be approximately $28 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 and restated on February 8, 2019, has a maturity date of February 8, 2024. As of June 30, 2019, the elected commitment amount under our credit facility was $600 million, with $115 million outstanding against that commitment amount resulting in $485 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 2019.

Advances on the credit facility bear interest, at our option, based on (i) a Eurodollar rate (substantially equal to the LIBOR) or (ii) the prime rate as quoted by *The Wall Street Journal* ("Prime Rate") (5.5% at June 30, 2019). The credit facility's interest rates on Eurodollar rate advances and Prime Rate advances vary, with interest margins ranging from 150 to 250 basis points and 50 to 150 basis points, respectively, per annum depending on the debt balance outstanding. We pay commitment fees on the unused portion of the available commitment of 37.5 to 50 basis points per annum depending on the debt balance outstanding.

In conducting our business, we may use various financing sources, including the issuance of (i) fixed and floating rate debt and (ii) partnership units. We may also sell assets. Additional partnership units may be of a class different from those currently issued and outstanding as determined from time to time by the board of directors of our ultimate general partner. 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 June 30, 2019, we had $63.9 million of unrestricted cash on hand.

At June 30, 2019, the elected borrowing base under our credit facility was $600 million, with $485 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.

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 "B1" 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 June 30, 2019 was $2,656.6 million, consisting of debt of $1,308.8 million and partners' capital of $1,347.8 million. Our debt to book capitalization was 49.3% and 45.8% at June 30, 2019 and December 31, 2018, respectively. Our ratio of current assets to current liabilities was 2.19 to 1.00 at June 30, 2019 as compared to 5.43 to 1.00 at December 31, 2018.

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 six months ended June 30, 2019, we received an average of $54.00 per barrel of oil, $0.37 per Mcf of natural gas and $10.92 per barrel of natural gas liquids before consideration of commodity derivative contracts compared to $61.92 per barrel of oil, $1.44 per Mcf of natural gas and $18.97 per barrel of natural gas liquids during the six months ended June 30, 2018. Although commodity prices fell significantly during 2016, the higher prices during 2017 through 2019 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 six months ended June 30, 2019.

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 June 30, 2019, 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 June 30, 2019, the fair value of our financial derivatives is a net asset of $68.1 million. All but one 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. The one counterparty to our financial derivatives that is not a party to our credit agreement is a major market participant of high credit quality. Under the terms of our financial derivatives instruments with this counterparty, we do not have exposure to margin calls and our relationship is on an unsecured basis subject to a credit limit established by the counterparty. 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 H to the Condensed Consolidated Financial Statements 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 and fixed basis differential 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 price and basis swap agreements as of June 30, 2019 was a net asset of $68.1 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 $80.8 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 NYMEX WTI oil fixed price swap agreements and the weighted average swap prices as of June 30, 2019:

	Projected Proved Production Covered (a)	Weighted Average Swap Prices	
	Crude Oil	**Crude Oil**	
Remainder of 2019	76%	$	62.39
2020	41%	$	64.17

(a) Based on the internally-prepared reserve evaluation effective July 1, 2019 utilizing oil price of $57.90

The following table lists the percentage of our projected oil production from proved properties covered by Midland-Cushing differential fixed price swap agreements and the weighted average swap prices as of June 30, 2019:

	Projected Proved Production Covered (a)	Weighted Average Swap Prices	
	Oil - Midland-Cushing differential	**Oil - Midland-Cushing differential**	
2019	76%	$	(1.00)
2020	50%	$	(0.65)

(a) Based on the internally-prepared reserve evaluation effective July 1, 2019 utilizing oil price of $57.90

Our actual production may materially vary from the amounts estimated in the July 1, 2019 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 2019. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the six months ended June 30, 2019:

	Derivative Instruments Net Assets (Liabilities) (a)
(in thousands)	**Commodities**
Fair value of contracts outstanding at December 31, 2018	$ 250,751
Changes in fair values (b)	(157,843)
Contract maturities	(24,814)
Fair value of contracts outstanding at June 30, 2019	$ 68,094

(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, 2018, filed with the trustee on March 11, 2019. 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 August 9, 2019.

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)